THE ENERGY OF ENERPLUS

2002 annual report

Created in 1986, **ENERPLUS RESOURCES FUND** is North America's largest conventional oil and natural gas income fund. Enerplus offers investors the benefits of owning a large, diversified portfolio of income generating crude oil and natural gas properties without the exploration risks commonly associated with traditional exploration and production companies. As an experienced acquirer, operator and exploiter, Enerplus invests in mature crude oil and natural gas producing properties located primarily in western Canada with predictable production profiles, long reserve life indices, high cash netbacks and opportunities for low risk development. The cash flow from these properties is distributed to Unitholders on a monthly basis, providing them with an investment within the energy sector that has outperformed the TSX Oil and Gas Producers Index over both the short and long-term.

2002 SELECTED COMBINED RESULTS

for the year ended December 31	2002	2001[1]
Operating		
Average Daily Volumes		
Natural gas (Mcf/day)	**210,517**	203,727
Crude oil (bbls/day)	**23,288**	24,010
NGLs (bbls/day)	**4,410**	4,650
Total (BOE/day) (6:1)	**62,784**	62,615
% natural gas	**56%**	54%
Established Reserve Life Index (years)	**13.8**	14.0

	2002	2001[1]	2002	2001[1]
	CDN$		US$ [2]	
Average Selling Price Pre-Hedging				
Natural gas (per Mcf)	**$ 3.87**	$ 5.22	**$ 2.46**	$ 3.37
Crude oil (per bbl)	**34.37**	31.09	**21.89**	20.08
NGLs (per bbl)	**25.68**	32.09	**16.36**	20.72
Financial (combined basis) ($000)				
Oil and gas sales before hedging	**$ 630,167**	$ 713,933	**$ 401,353**	$ 461,058
Proceeds (cost) of hedging	**(8,717)**	47,789	**(5,552)**	30,862
Royalties, net of ARTC	**131,837**	158,760	**83,967**	102,527
Operating costs	**134,387**	138,218	**85,591**	89,261
Netback	**355,226**	464,744	**226,243**	300,132
General and administrative	**16,039**	14,940	**10,215**	9,649
Management fees	**21,576**	12,066	**13,742**	7,792
Interest expense, net of interest and other income	**17,728**	19,287	**11,291**	12,456
Capital taxes	**5,483**	5,248	**3,492**	3,389
Restoration and abandonment cash costs	**4,548**	3,261	**2,897**	2,106
Funds flow from operations	**289,852**	409,942	**184,606**	264,740
Cash withheld for debt reduction	**46,344**	56,100	**29,516**	36,229
Debt/funds flow ratio	**1.2x**	1.0x	**1.2x**	1.0x

(1) *The 2001 operating and financial information reflects the combined results of Enerplus and EnerMark as if the Merger had been effective January 1, 2001. Combined information provides an historical perspective of the capabilities of the combined entity. This information is also relevant as both Enerplus Resources Fund and EnerMark Income Fund have been managed by the same management group since inception. This presentation does not conform to Canadian Generally Accepted Accounting Principles.*

(2) *All US$ amounts shown in the table above were converted using the Canadian to U.S. dollar exchange rate of $0.6369 (2001- $0.6458).*

2002 HIGHLIGHTS

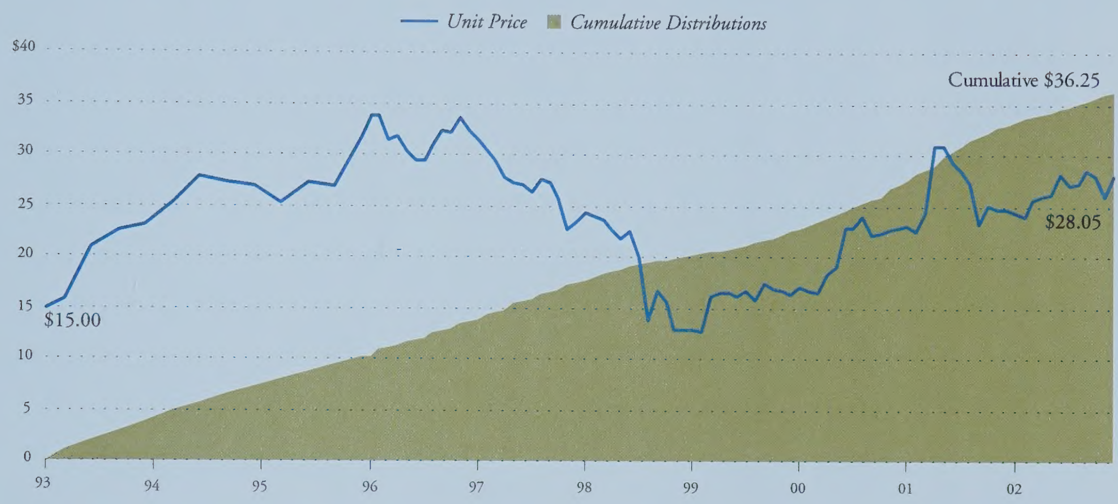
- Enerplus Unitholders realized a total return of 26.5% in 2002.
- Cash distributions paid to Unitholders totaled $3.32 per unit with an additional $0.62 per unit retained for debt repayment.
- The Fund increased its established crude oil and natural gas reserves by 6% over 2001 levels, with over 14.9 MMBOE of established reserves added through our successful development program.
- 300 net wells were drilled with a success rate of 99% through the Fund's development program.
- Enerplus successfully completed over $218 million of acquisitions, acquiring reserves at an attractive cost of $8.22 per BOE.
- Successfully completed the inaugural cross-border equity financing raising over $200 million to fund acquisitions and development activities.
- Enerplus diversified its debt portfolio through the issuance of US$175 million senior, 12-year amortizing unsecured notes with the proceeds reducing the Fund's bank indebtedness.

2002 CASH DISTRIBUTION PER UNIT

Production Month	*Payment Month*	*Distribution CDN$*	*Exchange Rate*	*Distribution US$*
January	March	$ 0.20	$ 0.6325	$ 0.13
February	April	0.20	0.6353	0.13
March	May	0.28	0.6487	0.18
April	June	0.28	0.6518	0.18
May	July	0.28	0.6422	0.18
June	August	0.28	0.6350	0.18
July	September	0.28	0.6352	0.18
August	October	0.30	0.6369	0.19
September	November	0.30	0.6307	0.19
October	December	0.30	0.6428	0.19
November	January, 2003	0.30	0.6504	0.19
December	February, 2003	0.32	0.6630	0.21
Total		$ 3.32		$ 2.13

10 YEAR SIMPLE RETURN

Represents a 10 year simple return of 32.9% per annum



10 YEAR COMPOUND RETURN

WHO WE ARE

Enerplus is North America's largest conventional oil and gas income fund. Our Unitholders have achieved an average annual simple return of 52.1% over the past three years.

Building on Success; Building for Success

Gordon J. Kerr
President &
Chief Executive Officer

Last year in my message to Unitholders, I described our vision for Enerplus to be the premier energy income fund in North America and outlined the strategic pillars that would serve as the foundation for achieving this vision. It is our mission "to be a top quartile performer, within the energy income fund sector, providing above average returns to our Unitholders and recognized for responsibility, creativity, consistency and as an employer of chöice". We liken this somewhat to a marathon race as opposed to a sprint. Our goal is to provide value to our Unitholders with consistency over the long term.

our mission

To be a top quartile performer within the energy income fund sector, providing above-average returns to our Unitholders and recognized for our responsibility, creativity, consistency and as an employer of choice.

In 2002, Enerplus achieved a number of successes consistent with our vision, not the least of which was a total return to our Unitholders of 26.5% on the strength of our unit price and cash distributions, placing us again in the top quartile of performance within our sector. In fact, over the last three years, Enerplus Unitholders have received an average annual total return of 52.1% putting us at the top of our conventional oil and gas income fund peer group. In addition, we achieved record production levels averaging 62,784 barrels of oil equivalent ("BOE") per day during 2002, exiting the year at 67,800 BOE per day, and a record reserve level of 330.4 MMBOE of established reserves weighted 57% to natural gas. The Fund's reserve life index has been maintained in the order of 13.8 years.

Emanating out of our supporting strategies, our growth in production and reserves was attributable to both the successes in our exploitation activities and in acquisitions. During 2002, we drilled 300 net wells with a 99% success rate, the majority of which were targeted on our shallow natural gas properties. In addition, we acquired over $218 million worth of oil and gas properties at an average cost of $8.22 per BOE, with our largest transaction being the acquisition of Celsius Energy Resources Ltd., a Canadian subsidiary of a U.S.–based oil and gas company. As discussed last year, we have taken a proactive approach to stimulating acquisition deal flow and the Celsius transaction is a direct result of this approach. As well, we have just closed our first major acquisition of 2003, the Canadian subsidiaries of U.S.–based PetroCorp Incorporated, for $167.6 million that includes production weighted 74% to natural gas, again as a result of our proactive acquisition efforts.

Heather J. Culbert
Senior Vice President, Corporate Services

Garry A. Tanner
Senior Vice President, & Chief Operating Officer

Eric P. Tremblay
Senior Vice President, Capital Markets

Robert J. Waters
Senior Vice President & Chief Financial Officer

Jo-Anne M. Caza
Vice President, Investor Relations

A strategic acquisition for Enerplus in 2002 was the acquisition of a 16% working interest in Oil Sands Lease #24 in the Alberta oil sands fairway. The Alberta oil sands is a world-class resource expected to produce in excess of one million barrels of oil per day in 2003 and will play a pivotal role in the future of Canadian oil production in the years to come. Not only is our investment in Oil Sands Lease #24 significant on its own economic merits and scope, but it also allows the Fund to gain knowledge and positioning in this strategic asset base with a relatively low capital investment. A commercial steam assisted gravity drainage ("SAGD") project is currently under way with first production expected in 2004.

We have maintained a strong balance sheet and the financial flexibility to execute on our exploitation and acquisition opportunities.

Building from our strategy of accessing additional sources of capital, we successfully completed two significant capital transactions in 2002. First, we placed US$175 million of senior unsecured 12 year notes at a very attractive all-in rate of 6.62% with major institutional investors in the United States. This placement not only diversified our sources of debt financing on a long-term basis, but also provided a critical review of our credit worthiness. Second, we completed our inaugural cross border equity issue in the last quarter of the year. As we began marketing the issue, there was a tightening in the Canadian market given the significant number of new trust-structured issues facing investors. Despite this tightening, we were able to successfully raise over $200 million as a consequence of our cross border access. As a result of our successful issues and an increase in our total borrowing capacity to $700 million, we have maintained a strong balance sheet and the financial flexibility to execute on our exploitation and acquisition opportunities.

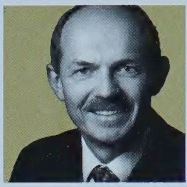
To ensure our continued success in both the exploitation and operation of our asset base, especially in view of our increasing size, in 2001 we began the process of bringing increased focus of smaller teams onto geographically defined play areas. In 2002 we

Daryl W. Cook
Vice President, Operations

Ian C. Dundas
Vice President & Director, Business Development

Wayne T. Foch
Vice President, Finance

David A. McCoy
General Counsel & Corporate Secretary



Daniel M. Stevens
Vice President, Development Services

completed the transition by introducing multi-disciplined teams structured around geographic business units. This transition has required significant input, resources, and dedication from all areas of our organization not to mention patience. I am truly grateful to all our staff for making it a reality. The value creation opportunities and strategies being undertaken are discussed more fully in the Business Unit Overviews section of this annual report.

Recent Developments

Concurrent with the release of our annual results we have also announced a proposal for internalization of the management contract held by Enerplus Global Energy Management Company ("EGEM") through the purchase of EGEM (the "Proposal"). The details of this Proposal are set out in the information and proxy circular in respect of the annual general and special meeting of Enerplus Unitholders to be held April 23, 2003.

RBC Dominion Securities Inc., advisors to the Special Committee of the Board, have provided a positive fairness opinion in respect of the Proposal. Both executive management of the Fund and the Board are in favour of the Proposal, which will eliminate all management fees going forward and thereby provide additional cash flow which will be accretive to distributions. All members of the executive management team will continue on in their existing capacities through and subsequent to the Proposal.

Other recent developments affecting the Fund relate to the introduction of the Sarbanes-Oxley Act in the U.S. This act was introduced as a consequence of the numerous irregular corporate activities which have plagued the U.S. markets over the past two years. The Act is intended to re-establish integrity and credibility with investors in the U.S. markets. As the Fund, through the Board and its Manager,

has maintained a high level of corporate governance, I together with our CFO will be able to meet the newly instituted certification requirements under the Act.

Finally, there is the matter of the Kyoto Accord and Canada's ratification of this Accord. While we still await many details of the implementation plan, the oil and gas industry has taken some comfort with the federal government's position to cap the emission reduction targets for the industry and the cost of emission credits. We do not expect this to be a material cost factor for the Fund's operations.

2003 Outlook

As we move forward into 2003, there are a number of external developments affecting our outlook. The most immediate and significant is the impending conflict in the Middle East. The threat of war and supply disruption, the latter being exacerbated by the strikes in Venezuela, has caused a significant upward spike in crude oil prices. Compounding this further has been the run up in natural gas prices as reflected through both the U.S. and Canadian indices. As a producer of both crude oil and natural gas, Enerplus has benefited from the price movements of both commodities. As a result, we recently announced an increase in the monthly cash distribution to 35 cents per unit for the month of March. Based upon current production levels and commodity prices, this level of distribution will allow us to continue to fund a significant portion of our capital spending program out of cash flow.

We have shifted our acquisition and development focus to be more heavily weighted toward natural gas although we will continue to have a relatively balanced portfolio of oil and gas assets.

There is an expectation that pending the outcome of the situation in the Middle East, crude oil prices could come down quickly on the restoration of Middle East and Venezuelan supply. Natural gas, however, is being driven by more fundamental supply/demand imbalances that support a more compelling case for continued strong natural gas prices, although demand destruction and a weak U.S. economy are expected to temper the absolute price levels. Based on this outlook, we have shifted our acquisition and development focus to be more heavily weighted toward natural gas although we will continue to maintain a relatively balanced portfolio of oil and gas assets.

We will continue to monitor the commodity price markets and enter into hedging arrangements in accordance with our hedging strategies. Under these strategies it is our intention to provide downside price protection on a portion of our production while maintaining significant exposure to upside price movement and

at the same time ensure we achieve positive economic returns on our exploitation and acquisition activities.

We will also be focused on realizing the expected benefits of our reorganization into Business Units. This reorganization has brought additional focus on improving the value creation and business results from all of our existing assets. In the last two years combined, we have seen record levels of reserve additions and revisions which reflect our successful development efforts to create value. We will continue these efforts in 2003 and in this regard, our Board has approved a capital development budget of $155 million for 2003. The budgeted amount does not include an allocation for acquisitions as these will be considered separately as opportunities are brought forward. We will continue to be proactive in our acquisition activities and to focus our oil and natural gas asset base as we target to acquire attractive properties with solid fundamentals and upside value creation potential. With respect to acquisitions, the proposed internalization of the management fee arrangement, if approved, will better position the Fund for consolidation in the energy trust sector should such opportunities provide added value for our Unitholders. In addition, we will continue to monitor the entire energy related acquisition market for opportunities that we can proactively pursue to add long term value.

In the last two years, we have seen record levels of reserve additions and revisions which reflect our successful development efforts to create value.

I want to once again thank my fellow board members for their support, guidance and diligence in providing strategic direction for the Fund, with a special thanks to Mr. Arne Nielsen who resigned from our board this last year after providing many years of service to the Enerplus organization. I also want to thank all the members of our organization who have continued to demonstrate the drive and dedication necessary for the successes we have achieved and will continue to achieve.

On behalf of the Board of Directors,

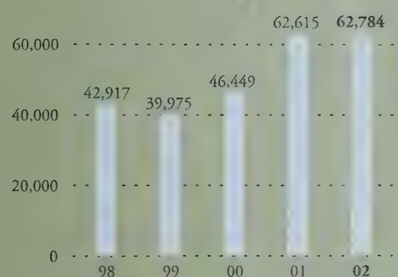
Gordon J. Kerr
President &
Chief Executive Officer
March 7, 2003

WHAT WE DO

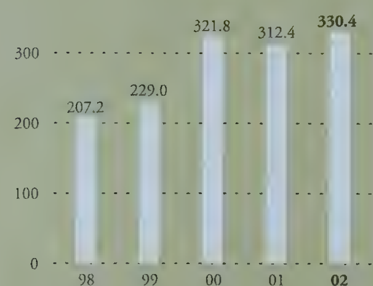
Employing a full compliment of technical, operating and administrative staff, Enerplus has proven itself an efficient operator, developer and acquisitor.

Business Units

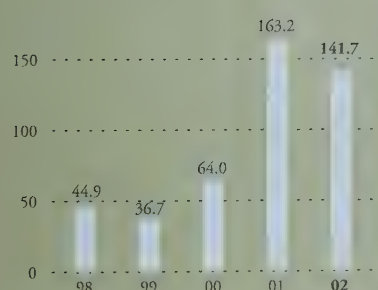
- *North*
- *South*
- *East*
- *Central*
- *Joint Venture/Non-Operated (included in all units)*



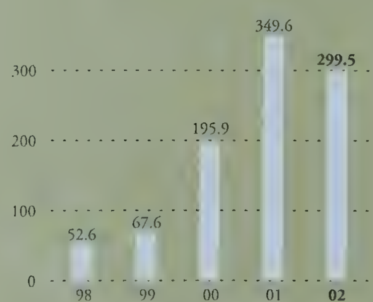
Production
(BOE/day)



Established Reserves
(MMBOE)



Development Capital Spending
($ millions)



Drilling Activity
(Number of net wells)

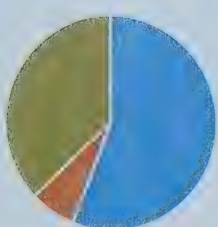
** all information combined to reflect EnerMark and Enerplus*

WHAT WE DO

Our growth has been achieved through accretive acquisitions and low-risk development.

Created in 1986, Enerplus is Canada's oldest and largest conventional oil and gas income fund with a diverse oil and natural gas asset base located primarily in Western Canada. The Fund pays investors a large portion of the net cash flow from its crude oil and natural gas properties on a monthly basis. Employing a full complement of technical, operating and administrative staff, Enerplus has proven itself as an effective and efficient operator and developer over the last 17 years and is a leader in the income fund sector. Our growth has been achieved through accretive acquisitions and low-risk development versus the higher risk exploration activities pursued by more traditional exploration and production companies.

PRODUCTION



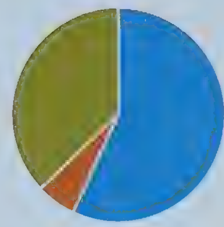
2002 Average Daily Production Volumes

- Natural Gas 56%
- Natural Gas Liquids 7%
- Crude Oil 37%

Enerplus achieved average daily production volumes of 62,784 BOE during 2002, virtually unchanged from those levels attained during 2001 by the combined Enerplus and EnerMark funds. The Fund's December exit production rate of 67,800 BOE/day reflects the additional volumes associated with the Celsius acquisition that closed in October of 2002. Enerplus enjoys an above-average reserve life index of 13.8 years, one of the highest in the sector. Enerplus operates approximately 65% of current production and owns interests in over 10,000 wells producing from over 250 properties. The property and product diversity within the Fund minimizes the risks associated with any single property, area, or commodity.

RESERVES

Enerplus ended 2002 with a record 330.4 MMBOE of established reserves, up 6% from 2001 and the highest level of reserves achieved in the Fund's history. Acquisition activities, net of dispositions, added 26.0 MMBOE of established reserves with development activities resulting in the addition of 14.9 MMBOE of established reserves, also a record achievement. Significant shallow natural gas reserve additions were realized at Medicine Hat, Hanna Garden, Verger, and Countess while major oil-related reserve additions were achieved at Giltedge, Joarcam and Gleneath.



2002 Reserves at Dec. 31

- Natural Gas 57%
- Natural Gas Liquids 6%
- Crude Oil 37%

2002 Reserves Summary	*Crude oil MMbbl*	*Natural gas Bcf*	*NGLs MMbbl*	*Total MMBOE*
Total established reserves at December 31, 2001	113.7	1,081	18.5	312.4
Proven, producing	94.9	787	14.0	240.1
Proven, non-producing	10.3	215	2.0	48.1
Total proven	105.2	1,002	16.0	288.2
Total probable at 50%	16.7	139	2.3	42.2
Total established reserves at December 31, 2002	**121.9**	**1,141**	**18.3**	**330.4**

Reserves Reconciliation	*Crude oil MMbbl*		*Natural gas Bcf*		*NGLs MMbbl*		*Total MMBOE*		*Established*
	Prov.	*Prob.*	*Prov.*	*Prob.*	*Prov.*	*Prob.*	*Prov.*	*Prob.*	*MMBOE*
Reserves at December 31, 2001	94.8	37.6	951.1	260.7	16.1	4.7	269.5	85.8	312.4
Acquisitions	7.8	5.5	79.3	19.5	1.1	0.4	22.1	9.1	26.6
Divestments	(0.6)	-	(0.2)	-	-	-	(0.6)	-	(0.6)
Production	(8.5)	-	(76.8)	-	(1.6)	-	(22.9)	-	(22.9)
Drilling, Development, Revisions	11.7	(9.7)	48.5	(2.6)	0.4	(0.5)	20.2	(10.6)	14.9
Reserves at December 31, 2002	**105.2**	**33.4**	**1,001.9**	**277.6**	**16.0**	**4.6**	**288.2**	**84.3**	**330.4**

The present value of the reserves at December 31, 2002 increased over 24% from the prior period using a 12% discount rate. Net asset value per trust unit increased by 11% on a year-over-year basis. This is significant considering the increase of 19% in the number of outstanding trust units at December 31, 2002, versus December 31, 2001. The increased value was primarily driven by an increase in commodity pricing and reserves. The natural gas and oil price forecasts used by Sproule Associates Limited ("Sproule") were significantly higher as compared to the prior year. Positive established reserve revisions and additions resulting from our successful development programs also helped increase net asset value per trust unit.

Present Worth of Production Revenue ($ millions) (including ARTC)

	10%	*12%*
Total established reserves at December 31, 2001	$ 1,785.4	$ 1,610.3
Proven, producing	1,805.7	1,665.5
Proven, non-producing	225.0	194.0
Total proven	2,030.7	1,859.5
Probable @ 50%	163.3	137.8
Total established reserves at December 31, 2002	**$ 2,194.0**	**$ 1,997.3**

Net Asset Value ($ millions, except per Trust Unit amount)

	10%	*12%*
Net asset value per Trust Unit as at December 31, 2001[1]	$ 20.46	$ 17.94
Present value of established reserves at December 31, 2002	$ 2,194.0	$ 1,997.3
Undeveloped acreage and seismic (acreage valued at $50/acre)	23.2	23.2
Bank debt	(361.7)	(361.7)
Working capital excluding distributions to Unitholders	(2.5)	(2.5)
Net asset value	**$ 1,853.0**	**$ 1,656.3**
Net asset value per Trust Unit as at December 31, 2002 [2]	**$ 22.35**	**$ 19.98**

(1) *Based on 69.532 million Trust Units outstanding as at December 31, 2001.*

(2) *Based on 82.898 million Trust Units outstanding as at December 31, 2002.*

Enerplus' net asset value is measured with reference to the present value of future net cash flows from our reserves as estimated by independent reserve engineers, Sproule Associates Limited, plus land values, adjusted for working capital and long-term debt at year-end. This calculation can vary significantly depending on the oil and natural gas price assumptions used by Sproule. In addition, this calculation ignores "going concern" value and assumes only the reserves identified in the Sproule report with no further acquisitions, despite our 17-year history of replacing production through acquisition and development.

Reserve Determination Methodologies

Sproule has evaluated 84% of the total value (discounted at 12%) of the Fund's year-end reserves. All evaluations of future net production revenues set forth in the tables are stated without provision for income taxes, general and administrative costs and management fees, which may apply. Probable reserves and values, as reflected under Established Reserves, have been reduced by a factor of 50% to adjust for risk.

Enerplus follows the Canadian practice of reporting gross production and reserve volumes, which are prior to the deduction of royalties and similar payments. In the U.S., production and reserve volumes are reported after deducting these amounts. The Canadian practice of using escalating prices and costs when estimating the quantities of reserves is also followed by Enerplus. In the U.S., reserve estimates are calculated using prices and costs held constant at amounts in effect at the date of the reserve report. Enerplus also follows the Canadian practice of using "Established Reserves", which include proven reserves and the probable reserves portion that has been reduced by a risk factor of 50%. As a consequence, our production volumes and reserve estimates may not be comparable to those made by U.S. companies.

The present value of future cash flow at December 31, 2002 was based upon crude oil and natural gas pricing assumptions prepared by Sproule. These forecasts are adjusted for reserve quality, transportation charges and the provisions of any applicable sales contracts. The base reference prices and exchange rate used by Sproule are as follows:

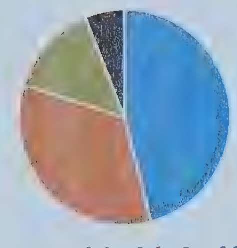
Pricing Assumptions

Year	*Crude oil WTI Cushing Oklahoma $US/bbl*	*Light Crude [1] Edmonton $CDN/bbl*	*Natural gas 30 day spot Plant Gate Price $CDN/MMBtu*	*Exchange Rate $US/$CDN*
2003	$ 25.99	$ 38.43	$ 5.72	0.633
2004	23.60	34.82	5.21	0.630
2005	21.63	32.22	4.60	0.620
2006	21.96	32.78	4.27	0.620
2007	22.29	33.90	4.42	0.610

Prices escalated at a rate of 1.5% per year thereafter, exchange rate held constant.

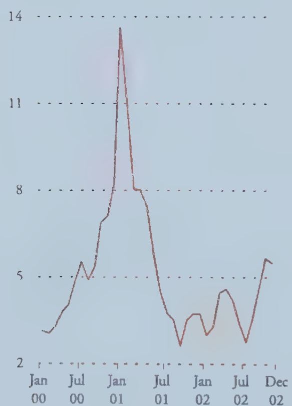
(1) *Edmonton refinery postings for 40° API, 0.4% sulphur content crude.*

MARKETING AND COMMODITY PRICING



Natural Gas Sales Portfolio

- Spot AECO (month or day) 46%
- Aggregator Netback Pools 34%
- Term Downstream Contracts 14%
- Term Fixed Price 6%



AECO Natural Gas Price (CDN$/Mcf)

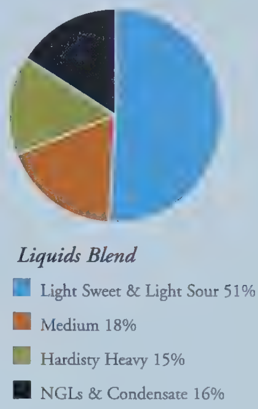
Natural Gas

The Fund's production was 56% weighted to natural gas throughout 2002. The price that Enerplus realizes for its natural gas production is based on the relevant North American pricing benchmarks: western Canadian natural gas is priced with reference to AECO Hub in Alberta, and U.S. natural gas is priced with reference to NYMEX at Henry Hub, Louisiana.

During 2002, the AECO monthly gas price index averaged CDN$4.07/Mcf, representing a decrease of 35% from the prior year. The NYMEX monthly gas price index averaged US$3.25/Mcf, representing a decrease of 26% from 2001. In both cases, there was a large price spike early in 2001 that significantly affected the annual average for the 2001 indices. Natural gas prices in 2002 moderated from the dramatic peak in 2001, however, they continued to trade in a volatile range between the lows of CDN$2.00/Mcf in the summer, to highs of CDN$6.50/Mcf at year-end. Record storage levels and weak economic demand at the start of the year were offset as the year progressed by colder winter temperatures, declining storage levels and support from strong crude oil prices.

The Fund's overall natural gas netback price (before hedging) at the plantgate was CDN$3.87/Mcf, representing a 21% decrease from the previous year. Enerplus' netback price did not decrease by the same magnitude as the AECO and NYMEX indices because the Fund has a balanced portfolio of spot sales, physical fixed price contracts, and term downstream delivery contracts that all respond differently to the market than the referenced indices. Nevertheless, at least 46% of the Fund's natural gas production is being directly marketed in western Canada in the spot market against the AECO index price. The 14% of production that is transported to and marketed directly in the Chicago / Midwest export market is priced against the NYMEX index price. Just over one third of the Enerplus gas production is dedicated to aggregator netback marketing pools managed by PanAlberta Gas, Progas Limited, and the Mirant Netback Pool (formerly managed by TransCanada Pipelines Limited). These netback pools also include portfolios of contracts comprised of fixed price, downstream U.S. based pricing mechanisms that served to dampen the effect of the overall decrease in the two key indices.

With the experience of colder winter temperatures and reduced inventory in storage, the natural gas market is expected to remain strong in 2003. The lack of exploration success, lagging drilling activity and natural reservoir declines keep tension on North American supplies. Demand for natural gas is dependent on the weather and the timing and strength of a North American economic recovery and are also linked indirectly to crude oil prices as an alternative energy source. Consequently, the fate of crude oil prices and the political tensions in the Middle East are expected to influence the natural gas market.



Liquids Blend

Crude Oil

The price that Enerplus receives for its crude oil is dependant upon a number of factors including the standard North American pricing benchmark, known as West Texas Intermediate ("WTI"), the Canadian/U.S. dollar exchange rate, hedging activity and the specific gravity of the crude oil. Crude oil with a light specific gravity trades at a premium to medium and heavier blends of crude oil that require more refining effort. As shown in the pie chart, 85% of Enerplus' crude oil and NGL stream is classified as either light or medium gravity.

The 2002 average price for the benchmark WTI crude oil was US$26.08/bbl, an increase of only one percent when compared to the 2001 price. It is interesting to note that where 2001 oil prices started the year at high levels (US$30.00/bbl) and ended the year much lower (US$18.00/bbl), in an almost mirror image, 2002 saw the lowest prices in January, with prices climbing steadily to a peak exceeding US$32.00/bbl by year-end. The early perceptions of weak economic demand and surplus crude oil inventories gave way later in the year to the political uncertainties surrounding Iraq and the Middle East, and strike-induced supply disruptions in Venezuela. Crude oil prices may continue to be volatile as the political tensions in the Middle East remain unresolved.

WTI Crude Oil Pricing ($US/bbl)

The Fund's average netback price for its crude oil production (before hedging) was CDN$34.37/bbl which reflects a 13% increase over that of 2001. Enerplus sells all of its crude oil at the lease site to marketers and refiners on contracts that fluctuate with monthly spot prices. The Fund realized a greater year-over-year increase than the WTI benchmark for two reasons. The refining differential applied to heavier grade crude decreased substantially from US$10.65/bbl in 2001 to US$6.45/bbl in 2002. The weaker Canadian dollar allowed Enerplus to realize higher prices as Enerplus' crude oil is priced with reference to the U.S. dollar denominated benchmarks.

HOW WE CREATE VALUE

The keys to our historical and future successes are our focus on portfolio management, value creation on our existing asset base and risk management.

Enerplus enjoyed a successful year on the acquisition front in 2002 closing $218.7 million of acquisitions resulting in the addition of 26.6 MMBOE of established reserves and 7,548 BOE/day of production. Established reserves and production were added at $8.22/BOE and $28,970 per BOE/day respectively. These acquisitions replaced 116% of 2002 production and will provide significant low-risk development potential in the future.

Enerplus has one of the most diversified, quality asset bases in the trust sector with an established reserve life of 13.8 years and a 57% reserve weighting toward natural gas. Acquisition efforts are driven by a disciplined approach to add accretive cash flow, replenish our value creation opportunities, and maintain a balance of oil and natural gas production (with a present emphasis toward natural gas). Our focus is on existing core areas that have provided historical value creation. The historic core areas have common producing characteristics that have been proven over time including limited reserve risk, limited cash flow risk and incremental upside potential. During 2002, Enerplus also positioned itself in potential new areas including the Athabasca oil sands. Periodically, we will also divest of certain smaller holdings to monetize higher risk assets and assets with limited value creation potential.

In keeping with our strategy of increasing ownership in existing long-life, key operated properties that offer upside potential, the first property acquisition completed in 2002 was the purchase of additional interests in the Medicine Hat Glauc. "C" crude oil property for $20.5 million. The transaction increased the Fund's working interest and added established reserves of 4.9 million barrels of crude oil and 2.0 Bcf of natural gas and daily production volumes of 500 barrels of crude oil and 600 Mcf of natural gas. Additional upside potential has been realized through the implementation of a waterflood program that has added incremental reserves and production to this property.

Strategic Investment in Oil Sands Lease #24: During the third quarter of 2002, Enerplus completed a strategic acquisition of a 16% working interest in Oil Sands Lease #24 for $16.4 million. Oil Sands Lease #24 is a 50,000-acre lease situated approximately 40 miles northwest of Fort McMurray in the Athabasca Oil Sands fairway of northeastern Alberta with both steam assisted gravity drainage ("SAGD") and mining potential. The long-term strategic nature of this investment, combined with modest initial capital exposure, provides Enerplus an ideal entry into the development of the Athabasca Oil Sands - a key driver in the future of the Western Canadian Sedimentary Basin. Over the longer term, this investment is expected to provide Enerplus unitholders exposure to significant low-cost reserves and stable production growth.

Initial assessment work for a SAGD project has been completed on the lease, including the drilling of 230 core hole wells, a third party independent engineering assessment, and the completion of a successful SAGD pilot project. The next phase of the project will consist of a commercial SAGD project that is scheduled to commence in 2003 with peak production expected by early to mid 2005. Following this project, Enerplus has the option to participate in full-scale development of the lease. Current plans by the operator contemplate development of up to two 30,000 bbl/day projects with production from the first 30,000 bbl/day SAGD project expected on stream by 2008. Once fully developed, each SAGD project is expected to have an established Reserve Life Index in excess of 25 years. Recoverable reserves associated with each 30,000 bbl/day SAGD development are estimated to be 275 million barrels of oil (44 million barrels net to Enerplus with a net cost of approximately $50 million). In keeping with current industry practices, Enerplus has not recorded any reserves for this investment but expects to record reserves as the projects are developed over time.

Established RLI in excess

Celsius Energy

- *$161.4 million*
- *production*
- *18 MMBOE of established reserves*
- *Over 300 low-risk development drilling locations*

Celsius Energy: In October 2002, Enerplus acquired Celsius Energy Resources Ltd. ("Celsius"), a wholly-owned subsidiary of Questar Market Resources Inc. for a total consideration of $161.4 million including costs and adjustments incurred in connection with the acquisition. This transaction is consistent with our strategy of expanding the production base in our core areas and acquiring significant low-risk development potential. Daily production volumes acquired consisted of 22.5 MMcf/day of natural gas, 1,724 bbls/day of crude oil, and 280 bbls/day of natural gas liquids (5,750 BOE/day) and added established reserves of 18 MMBOE. The Celsius assets provide excellent synergy with Enerplus' existing assets, particularly in the Verger, Countess, Pine Creek and Deep Basin areas and we have identified over 300 low-risk development drilling locations on the Celsius properties.

PCC Energy Inc. and PCC Energy Corp.: Subsequent to year-end, Enerplus acquired all of the outstanding shares and debt of PCC Energy Inc. and PCC Energy Corp., (collectively "PCC") which are wholly-owned Canadian subsidiaries of US-based PetroCorp Incorporated for $167.6 million. This transaction provides high-quality, long-life gas assets in large established pools and adds approximately 4,380 BOE/day of production and 17.2 MMBOE of established reserves after adjustments for a royalty arrangement to a third party which is structured as a Net Profits Interest. The properties have an established reserve life index of 10.7 years and 74% of the production is natural gas. Approximately 79% of the value of PCC is concentrated in eight properties, which are high quality, long-life, deep-gas properties with drilling potential. The operating costs associated with the PCC assets are approximately $4.00/BOE. The production and reserves associated with this acquisition will be recorded by Enerplus from March 2003 onward.

PCC Acquisition

- *$167.6 million*
- *4,380 BOE/day of production*
- *17.2 MMBOE of established reserves*
- *10.7 year established RLI*
- *$4.00/BOE operating costs*

Divestments

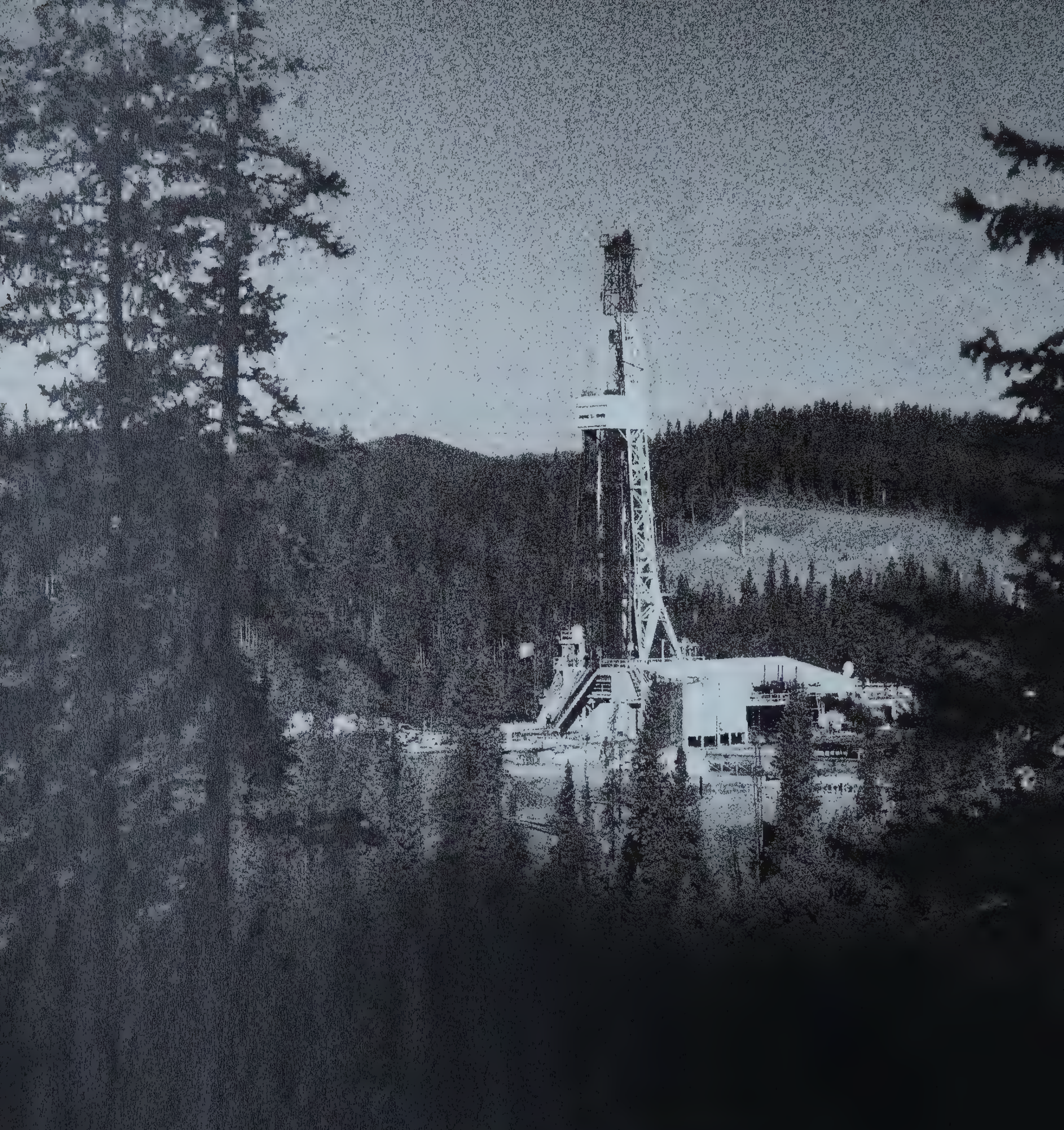
Enerplus continually pursues divestment opportunities to upgrade its portfolio of properties by monetizing higher risk, non-core assets with limited development potential. The assets sold are generally minor working interests and represent a small percentage of the Fund's overall portfolio. In 2002, Enerplus divested $3.1 million of non-core properties that produced 202 BOE/day of production and had associated established reserves of 646 MBOE. Enerplus plans to continue with its divestment program in 2003

Acquisition Summary

	Crude oil bbls/day	*Natural gas Mcf/day*	*NGLs bbls/day*	*Total BOE/day*	*Total Cost/ daily BOE*
Daily Production[1]	3,064	25,098	301	7,548	$28,970

	Crude oil MMbbl	*Natural gas Bcf*	*NGLs MMbbl*	*Total MMBOE*	*Total Cost per BOE*
Reserves:					
Proven	7.8	79.3	1.1	22.1	$9.90
Established	10.5	89.0	1.3	26.6	$8.22

[1] *Enerplus received only a partial year benefit of the entire daily production volumes acquired in 2002, depending upon the closing date of each acquisition.*



DEVELOPMENT OPPORTUNITIES

Value creation within our existing asset base comes through the efficient development and recovery of oil and gas reserves.

Value creation within our existing asset base comes through the efficient development and recovery of oil and gas reserves. This requires operational and technical excellence, quality oil and gas assets, a keen understanding of risk and risk mitigants, and an organization adept at execution. Together these factors provide sustainable, consistent performance over an extended period.

During 2002, Enerplus successfully invested $141.7 million in value creation activities that improved the oil and gas production and recovery in our existing assets. We brought on approximately 11,575 BOE/day of new production at an average cost of $12,242 per daily barrel and added 14.9 million barrels (established) of new reserves. We drilled or participated in 300 net wells with a 99% success factor, optimized our core waterfloods, completed 66 land transactions, and expanded our inventory of future projects with emerging opportunities in coal bed methane, shallow gas development, oil sands and attractive light oil developments.

The Fund participated in drilling 421 gross wells in 2002, including 300 gross operated wells and 121 gross partner-operated wells. After taking into account partner working interests, Enerplus drilled 299.5 net wells in 2002 with an overall success rate of 99%. A significant number of these wells were operated shallow natural gas wells drilled in southeast Alberta and southwest Saskatchewan in the areas of Medicine Hat, Hanna Garden, Bantry, Verger and Fox Valley. Significant partner-operated natural gas wells were drilled in Deep Basin and Mount Benjamin while major operated oil developments were pursued at Joarcam, Giltedge, Gleneath and Pembina.

	Crude Oil		*Natural Gas*		*Dry & Abandoned*		*Total*	
(number of wells)	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Alberta	50.0	17.0	307.0	239.4	8.0	4.2	365.0	260.6
Saskatchewan	28.0	13.7	28.0	25.2	-	-	56.0	38.9
British Columbia	-	-	-	-	-	-	-	-
Total	78.0	30.7	335.0	264.6	8.0	4.2	421.0	299.5

Success Rate: 99%

Enhanced Recovery Projects

Enhanced recovery projects can significantly improve the recovery from existing oil and natural gas pools and are essential to maintaining production and reserve life in maturing basins like The Western Canadian Sedimentary basin. Enerplus is currently focused on a number of secondary recovery waterfloods in our portfolio which make up 23% of our current production as well as being involved in a number of tertiary recovery projects managed by major oil companies. By focusing our operating knowledge on waterfloods and exposing ourselves to attractive tertiary projects through minor working interest positions with the majors, we can leverage our expertise while maintaining a well-diversified asset base.

Waterflood	*Operator*	*Working Interest (%)*	*2002 Average Daily Production (BOE/day)*
Joarcam Viking	Enerplus	80	3,189
Pembina	Enerplus	100	2,507
Giltedge	Enerplus	100	1,699
Med. Hat Glauc. "C"	Enerplus	72	1,430
Progress	Enerplus	100	1,112
Gleneath	Enerplus	80	1,094
Kessler	Enerplus	100	588
Chauvin North	Enerplus	100	567
Silver Heights	Enerplus	89	510
Shorncliffe	Enerplus	74	460
Pouce Coupe	Enerplus	49	392
David	Enerplus	100	361
Heward	Enerplus	100	294
Battle Creek	Enerplus	100	286
Neptune	Enerplus	90	176
SubTotal			14,665
Tertiary:			
Turner Valley	Talisman	5.0	230
Swan Hills Unit No. 1	Devon	1.1	150
Nelson Viking	Glencoe	5.4	20
Weyburn	EnCana	0.1	10
Sub Total			410
Total			**15,075**

Land Oriented Projects

Enerplus enjoys a large producing and undeveloped land position throughout western Canada as well as an extensive seismic database and operating knowledge. The combination of asset knowledge and ownership positions Enerplus to negotiate attractive farm-ins (accessing land owned by others), farm-outs (providing others access to Enerplus owned land), joint ventures and other industry deals. Enerplus is also able to maximize value from existing assets such as underutilized facilities, selective seismic lines and land use agreements.

Activity in 2002 included 31 farm-outs, 19 poolings and seven farm-ins that resulted in 50 well commitments on our lands.

Activity in 2002 included 31 farm-outs, 19 poolings, and seven farm-ins that resulted in 50 well commitments on our lands and our commitment to drill 10 farm-in wells on the lands of industry partners. One hundred percent of our committed wells were successful. Additional value may be realized over time from future drilling locations or from additional committed wells that have not yet been drilled.

2002 Land Summary

	Developed Acres		*Undeveloped Acres*		*Royalty Acres*
as at December 31 (000s)	*Gross*	*Net*	*Gross*	*Net*	*Gross*
Alberta	2,432.2	880.1	907.5	382.7	766.7
British Columbia	237.2	50.2	121.6	56.1	173.4
Saskatchewan	171.1	96.1	34.1	23.8	132.1
Other	0.7	0.6	0.6	0.6	180.8
Total Acres	**2,841.2**	**1,027.0**	**1,063.8**	**463.2**	**1,253.0**

BUSINESS UNIT OVERVIEW

In 2002, Enerplus reorganized into a business unit structure to improve operating results and capital efficiency.

During 2002, Enerplus reorganized from a traditional functionally-aligned organization into a business unit structure with four geographically distinct business units and a joint venture business unit. This restructuring will allow us to better focus our activities, improve operational and technical excellence, improve operating results and increase capital efficiency. Each of these five business units is a profit centre with a complement of engineers, geologists, operations personnel, and landmen supported by an efficient corporate structure. Skill sets within each business unit are tailored to compliment the unique demands and opportunities within each area. The following is a summary of the business units and the value creation activities pursued in 2002.

JOINT VENTURE BUSINESS UNIT

This business unit accounts for one third of Enerplus' production and encompasses all partner-operated properties in Western Canada from northeast British Columbia to southeast Saskatchewan. These properties provide exposure to a wide variety of reservoirs, play types, and enhanced recovery projects that offer diversification to our asset base. The Joint Venture Business Unit also provides exposure to higher impact, more technically sophisticated projects that the Fund would not pursue on its own.

key metrics:

- *Production:* *7,823 bbls/day Liquids* *85,470 Mcf/day Natural gas* *22,068 Total BOE/day*
- *Established Reserves:* *33.1 MMbbl Liquids* *440.7 Bcf Natural Gas* *106.5 MMBOE Total*
- *Reserve Life Index:* *11.8 years*
- *Total 2002 Development Spending: $30.8 million*

Major Properties

		2002 Production		*Established*
	Liquids bbls/day	*Natural Gas Mcf/day*	*Total BOE/day*	*Reserve Life Index (yrs)*
Mount Benjamin	10	11,063	1,854	14.4
Elmworth	360	5,001	1,194	9.5
Progress	118	4,104	802	6.2
South Wapiti	168	3,491	750	6.9
Hayter	679	16	682	5.5
Other	6,488	61,795	16,786	12.5

2002 Value Creation

The Joint Venture Business Unit invested $30.8 million during 2002 resulting in incremental production of 2,400 BOE/day at an average cost of $12,800 per BOE/day. Key capital projects in 2002 included the sweet, liquids rich natural gas plays in Deep Basin operated by Burlington and the foothills deep natural gas play in Mount Benjamin operated by Petro-Canada. Both areas have shown significant production increases since Enerplus acquired its interests.

The Joint Venture Business Unit also includes a unique nitrogen injection pilot in the Turner Valley area outside of Calgary. This pilot, operated by Talisman, began operation in September of 2002 and if successful, will lead to a full scale development program designed to recover an estimated additional 3% to 10% of the one billion barrels of original oil in place, 1.5 to 5.0 million barrels of crude oil net to the Fund.

2002 Key Capital Projects

Property	*Project*	*Product*	*Capital ($ millions)*	*Initial Prod. (BOE/day)*	*$/BOE/ day*
Deep Basin	Drilled 28 wells	Nat. Gas	$ 2.8	250	$ 11,200
Mount Benjamin	Drilled 3 wells	Nat. Gas	5.7	1,000	5,700
Jenner	Drilled 10 wells	Oil	1.2	200	6,000
Other			21.1	950	22,200
Total			$ 30.8	2,400	$ 12,800

Mount Benjamin is a deep foothills natural gas play operated by Petro-Canada. During 2002, three wells were drilled and successfully completed, testing between 10 MMcf/day and 20 MMcf/day of natural gas. As shown in the graph below, the additional production was tied in late in 2002 providing in excess of 15 MMcf/day of sales as we enter 2003. Since acquiring this property in 2000, a total of 5 wells have been drilled with a 100% success rate, increasing production in a prolific natural gas area where significant production declines are common.

Production at Mount Benjamin has more than doubled since acquired in 2000

Mount Benjamin Production Profile

2003 Outlook

Current natural gas prices continue to support numerous development activities

Robust oil and gas prices are expected to support continued drilling and development across the industry and therefore we expect capital expenditures to hold flat or increase in our partner-operated areas in 2003. We anticipate spending approximately 75% of our joint venture capital budget on gas-weighted projects and 25% on oil-weighted projects. Additionally, Enerplus will be funding the initial phases of the Oil Sands Lease #24 SAGD development project and expects to spend $7.0 million on this project in 2003 with first production expected in 2004.

SOUTHERN BUSINESS UNIT

The Southern Business Unit is our most active development area encompassing properties in southern Alberta and Saskatchewan. It contains our core shallow gas development areas as well as a broad range of oil plays. The majority of the Fund's operated development drilling is conducted in this business unit with over 200 operated shallow natural gas wells drilled in 2002. The Medicine Hat Glauc. "C" waterflood, in which Enerplus acquired additional working interest this year, is also in this business unit along with other significant Midale/Ratcliffe oil production.

key metrics:

- *Production:*
  3,250 bbls/day Liquids
  56,330 Mcf/day Natural gas
  12,638 Total BOE/day
- *Established Reserves:*
  23.3 MMbbl Liquids
  459.3 Bcf Natural Gas
  99.8 MMBOE Total
- *Reserve Life Index:*
  21.3 years
- *Total 2002 Development Spending: $47.6 million*

Major Properties

		2002 Production		*Established*
	Liquids bbls/day	*Natural Gas Mcf/day*	*Total BOE/day*	*Reserve Life Index (yrs)*
Hanna	2	12,616	2,105	41.3
Bantry	-	13,757	2,293	19.7
Med. Hat Glauc. "C"	1,226	1,222	1,430	24.2
Verger	8	7,609	1,276	18.6
Med. Hat Sun Valley	-	7,318	1,220	17.8
Other	2,014	13,808	4,314	12.5

2002 Value Creation

A total of $47.6 million was invested in 2002 resulting in incremental production of 3,720 BOE/day at a cost of $12,800 per BOE/day. The unit completed a significant farm-in with a junior exploration company during the year resulting in the Fund purchasing offset lands to add to our future drilling inventory of low-risk shallow gas development.

2002 Key Capital Projects

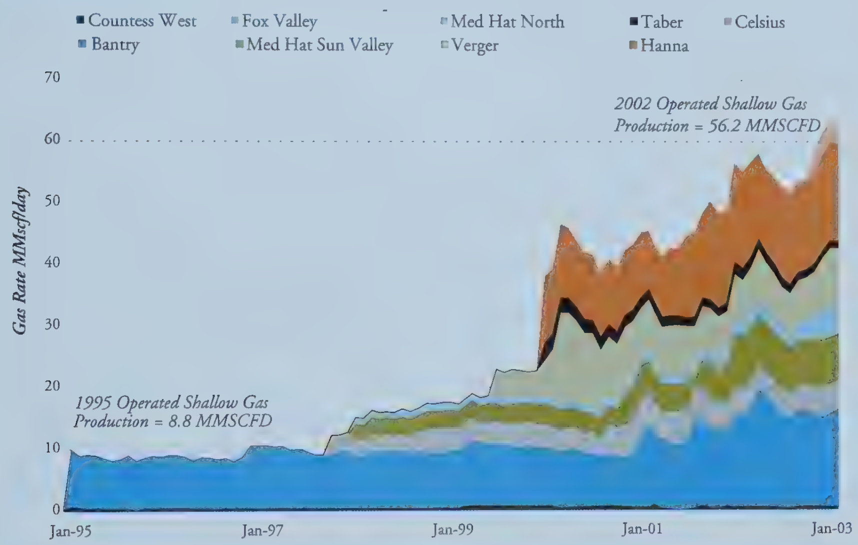
Property	*Project*	*Product*	*Capital ($ millions)*	*Initial Prod. (BOE/day)*	*$/BOE/ day*
Hanna	Drilled 61 wells	Nat. Gas	$ 12.9	520	$ 24,800
Med. Hat North	Drilled 53 wells	Nat. Gas	8.5	420	20,200
Verger	Drilled 33 wells, tied-in 51 wells	Nat. Gas	6.0	500	12,000
Bantry	Drilled 48 wells, refrac 15 wells, tied-in 52 wells	Nat. Gas	6.3	650	9,700
Other		Nat. Gas	13.9	1,630	8,500
Total			$ 47.6	3,720	$ 12,800

SOUTHERN BUSINESS UNIT

Since 1995, the Fund's shallow gas production has grown from under 10 MMcf/day to approximately 60 MMcf/day in the area through acquisitions and development drilling. The following graph shows the Fund's increase in production from the shallow natural gas areas over the past eight years.

Shallow natural gas drilling has added over 24 million BOE of additional reserves in the last two years

Shallow Gas Production Profile



2003 Outlook

We again plan to drill approximately 200 shallow natural gas wells in 2003

We plan to continue our shallow gas development drilling in 2003 including higher density drilling within our shallow gas locations. The recent Celsius acquisition has added approximately 300 locations to our existing project inventory. Confirmation of the viability of increased density of well spacing will add further development opportunities into the future. Regarding oil development, Enerplus plans to continue development of the Medicine Hat Glauc. "C" waterflood and pursue other waterflood opportunities in the area.

EASTERN BUSINESS UNIT

The Eastern Business Unit focuses on waterflood development projects and encompasses operated properties and lands in eastern Alberta and western Saskatchewan along the provincial border. This business unit is predominantly oil weighted with properties producing light sweet, medium quality and conventional heavy oil. The majority of these oil properties are under secondary recovery schemes to improve production and enhance recoverable oil reserves. Optimization of these secondary recovery projects is key to maximizing the value of the assets in this business unit.

key metrics:

- *Production:*
  8,883 bbls/day Liquids
  10,049 Mcf/day Natural gas
  10,558 Total BOE/day
- *Established Reserves:*
  41.3 MMbbl Liquids
  62.1 Bcf Natural Gas
  51.6 MMBOE Total
- *Reserve Life Index:*
  12.7 years
- *Total 2002 Development Spending: $36.4 million*

Major Properties

	2002 Production Liquids bbls/day	2002 Production Natural Gas Mcf/day	Total BOE/day	Established Reserve Life Index (yrs)
Joarcam	2,235	5,726	3,189	9.7
Giltedge	1,635	386	1,699	19.7
Gleneath	1,026	407	1,094	21.9
Auburndale	582	553	674	5.8
Kessler	571	101	588	7.6
Other	2,834	2,876	3,314	11.0

2002 Value Creation

The key waterflood recovery projects in the business unit were reviewed in 2002 to ensure that they were fully optimized. These reviews provided opportunities to infill drill, recomplete and restimulate wells to improve production capability and enhance oil recovery. The business unit invested $36.4 million in 2002 adding 2,990 BOE/day of production at a cost of approximately $12,200 per BOE/day.

2002 Key Capital Projects

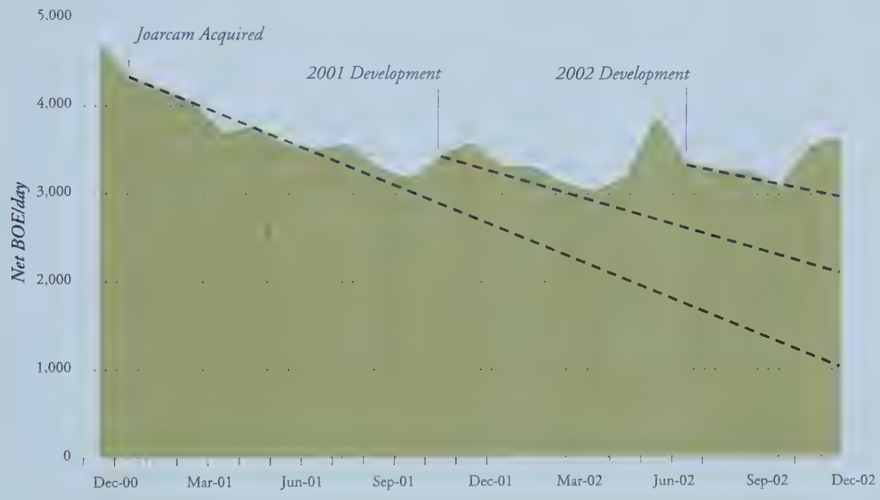
Property	*Project*	*Product*	*Capital ($ millions)*	*Initial Prod. BOE/day*	*$/BOE/ day*
Joarcam	Drilled 14 wells	Oil	$ 22.0	1,700	$ 12,900
Gleneath	Drilled 10 wells	Oil	4.8	590	8,100
Giltedge	Drilling/Facilities	Oil	1.9	300	6,300
Silver Heights	Drilling/Facilities	Oil	1.1	170	6,500
Other	Drilling	Oil	6.6	230	28,700
Total			$ 36.4	2,990	$ 12,200

EASTERN BUSINESS UNIT

A key project in 2002 was the continued development of Joarcam in central Alberta. Acquired in late 2000, Joarcam is our largest single producing field and has seen a significant decrease in the decline rate since we assumed operatorship. Through a series of optimization and development efforts we have leveled the decline rate from in excess of 30% to less than 10% per year and added 2.9 million barrels of established reserves.

We have added 2.9 MMBOE of established light, sweet crude oil reserves in Joarcam since its acquisition in 2000

Joarcam Production Profile



2003 Outlook

Development activities for 2003 will build off our historical success and continue to focus on improving and expanding our existing waterfloods to increase production and recovery. New shallow gas and coal bed methane potential will also be pursued in the area. Divestments of minor interests and acquisitions in our core properties will provide additional focus in the area.

We will continue to focus on improving and expanding our existing waterfloods to increase production and recovery

CENTRAL BUSINESS UNIT

key metrics:

Production:
4,466 bbls/day Liquids
36,113 Mcf/day
Natural gas
10,485 Total BOE/day

Established Reserves:
33.2 MMbbl Liquids
117.3 Bcf Natural Gas
52.7 MMBOE Total

Reserve Life Index:
14.9 years

Total 2002 Development
Spending: $13.9 million

The Central Business Unit is a mature producing area which lies to the west and southwest of the city of Edmonton and provides a variety of production predominantly weighted to light quality sweet oil and liquids rich natural gas. Given the relatively higher operating costs in many fields in this area, profitability is sensitive to commodity pricing and we focus our attention on controlling operating costs in order to maximize the value of these assets.

Major Properties

	2002 Production			Established
	Liquids bbls/day	*Natural Gas Mcf/day*	*Total BOE/day*	*Reserve Life Index (yrs)*
Pembina	2,265	1,450	2,507	32.3
Ferrier	218	4,358	944	6.3
Sylvan Lake	574	1,959	901	8.0
Kaybob South	227	2,920	714	17.7
Cherhill	171	2,901	655	3.4
Other	1,011	22,525	4,764	7.5

2002 Value Creation

Development activity was primarily targeted at maintaining light oil production in the Pembina and Sylvan Lake areas and developing new shallow gas production in Pembina, Bashaw and Sylvan Lake. A total of $13.9 million was invested in development activity during 2002, resulting in incremental production of 1,110 BOE/day at a cost of approximately $12,500 per BOE/day. An initiative to exploit the shallow gas potential in the Central Business Unit commenced in the latter half of 2002. The early results of this project have been encouraging and have led to further development planned in 2003 to assess the economic viability of the program.

2002 Key Capital Projects

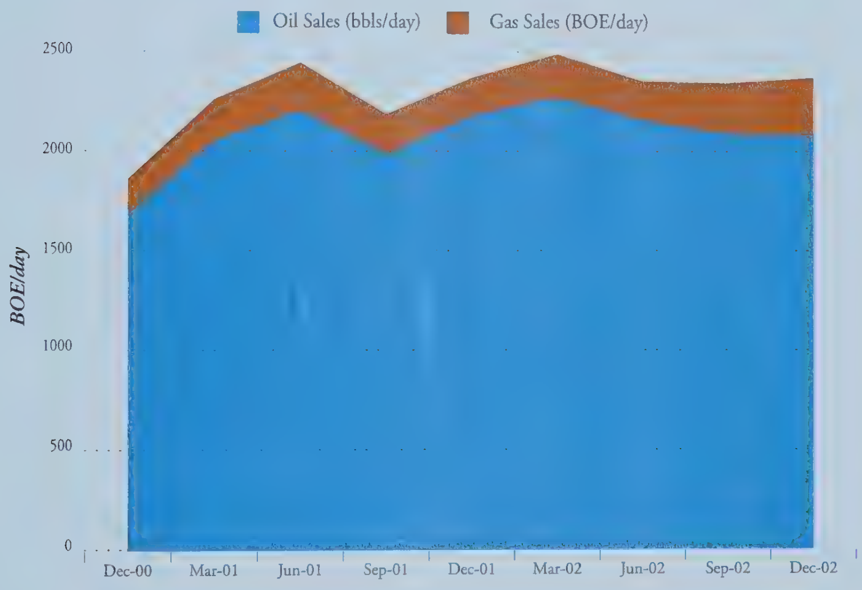
Property	*Project*	*Product*	*Capital ($ millions)*	*Initial Prod. BOE/day*	*$/BOE/ day*
Pembina	Drill/Recomplete	Gas/oil	$ 5.6	350	$16,000
Bashaw	Drilled 5 wells	Nat. gas	2.1	150	14,000
Sylvan Lake	Drill/Recomplete	Nat. gas	1.1	100	11,000
Other			5.1	510	10,000
Total			$13.9	1,110	$12,500

CENTRAL BUSINESS UNIT

Pembina is a large, low decline Cardium oil field that has benefited from on-going development which has increased production by 27% in just over two years. Recently, we have complimented the existing oil production with a shallow gas development program which has grown natural gas production by 64% from 1,050 Mcf/day in the third quarter of 2000 to 1,725 Mcf/day in the fourth quarter of 2002.

Pembina established reserves are up over 10 MMBOE in the last two years

Pembina Production Profile



2003 Outlook

Investment activity in 2003 will continue to be a key focus in the Central Business Unit with further development of our shallow gas program including the continued evaluation of coal bed methane potential. Our historical infill drilling and recompletion initiatives will also be continued to maintain our light oil production.

In 2003, we will compliment our light oil development with shallow gas development projects.

NORTHERN BUSINESS UNIT

The Northern Business Unit is a less developed area that encompasses all operated lands and production in northwest Alberta and northeast British Columbia. The business unit provides exposure to both light crude oil and liquids rich natural gas through a variety of Triassic to Cretaceous age reservoirs. This area tends to offer higher impact potential per well although there are fewer drilling locations.

key metrics:

- *Production:* *3,276 bbls/day Liquids* *22,555 Mcf/day Natural gas* *7,035 Total BOE/day*
- *Established Reserves:* *9.5 MMbbl Liquids* *61.2 Bcf Natural Gas* *19.7 MMBOE Total*
- *Reserve Life Index:* *8.9 years*
- *Total 2002 Development Spending: $13.0 million*

Major Properties

	2002 Production			*Established*
	Liquids bbls/day	*Natural Gas Mcf/day*	*Total BOE/day*	*Reserve Life Index (yrs)*
Valhalla	497	8,755	1,956	7.0
Progress	726	2,318	1,112	6.2
Bonanza	12	3,406	580	4.7
Pouce Coupe	299	555	392	15.6
Utikuma	353	53	362	8.1
Other	1,389	7,468	2,633	15.3

2002 Value Creation

During 2002 development activities were primarily focussed on improving light oil production at Valhalla and optimizing natural gas production at Valhalla, Bonanza, Progress and Komie through facility upgrades and development drilling. A total of $13.0 million was invested in this business unit on these activities and resulted in a production increase of 1,355 BOE/day at a cost of $9,600 per BOE/day.

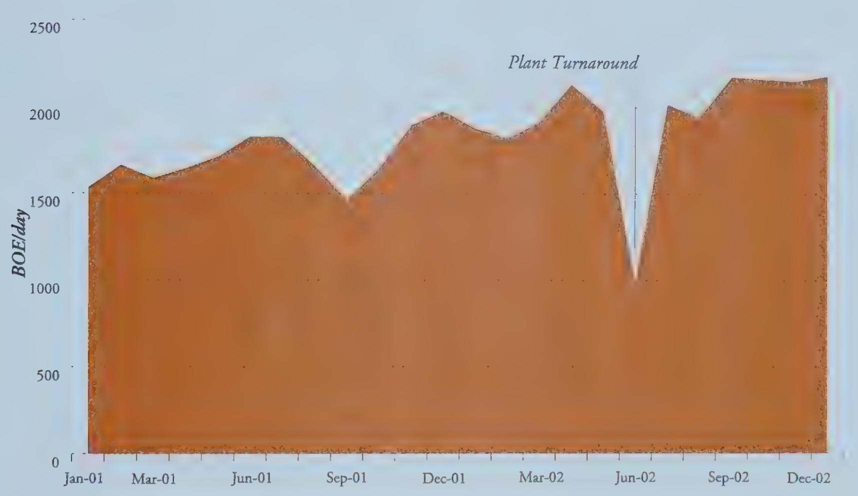
2002 Key Capital Projects

Property	*Project*	*Product*	*Capital ($ millions)*	*Initial Prod. BOE/day*	*$/BOE/ day*
Valhalla	Drilled 2 wells	Oil	$ 4.0	490	$ 8,200
Bonanza	Compression	Nat. gas	1.3	355	3,700
Glacier	Drilled/Recompleted 3 wells	Nat. gas	0.8	280	2,900
Other			6.9	230	30,000
Total			$ 13.0	1,355	$ 9,600

NORTHERN BUSINESS UNIT

Since acquiring Valhalla in 1996, production has steadily increased through our development efforts. Over the last two years, production has increased 42% from 1,536 BOE/day to 2,185 BOE/day. In 2002, two additional wells were drilled in the oil leg of the Valhalla Halfway J pool to enhance oil recovery and optimize the production from this pool.

Valhalla Production Profile



Valhalla production has increased by 42% over the last two years

2003 Outlook

Development activities for 2003 will target additional development at Valhalla and Progress to further enhance production and recoverable reserves. Efforts to leverage our existing acreage, a review of non-productive wellbores and our extensive seismic position are expected to further enhance our development opportunities in 2003 and into the future. The divestment of non-core properties in the north central Alberta area surrounding Gift Lake is being considered to further focus this business unit.

[illegible] forward will be focused on the Valhalla/Progress area

RISK MANAGEMENT

Our historical drilling success approaches 100% due to our disciplined approach to capital expenditures, a focus on proven core areas and concentration on low risk development versus exploration.

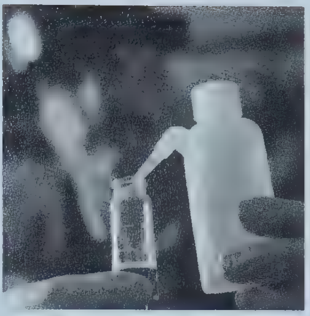
Active risk management is fundamental to long-term, consistent performance at Enerplus. During 2002 Enerplus continued to maintain a disciplined approach to capital spending, a well-diversified portfolio of oil and gas assets, rigorous due diligence on new acquisitions, an active commodity hedging program, adequate insurance, and a strong environment and safety program. Through risk mitigation and an avoidance of exploration activities, Enerplus is able to maximize distributions to unitholders and maintain a lower cost of capital within the oil and gas sector. While risk is inherent to the oil and gas industry, proper risk/return analysis and active risk mitigation has facilitated our long-term track record. Risk mitigation can be categorized into three primary areas: operations, environment/safety and financial.

Operations Risk Management

Enerplus is one of Canada's largest oil and gas producers with both an active acquisition/divestment program and capital development program. To manage risk in these areas, Enerplus adheres to the following guidelines:

- No one property represents more than 5% of our production which provides solid diversification and minimizes the potential of production shortfalls;
- Our historical drilling success approaches 100% due to our disciplined approach to capital expenditures, a focus in proven core areas and concentration on low-risk development versus exploration;
- New areas are stringently reviewed to ensure the risk adjusted returns are attractive and minimal capital is exposed to higher risk activities;
- Our acquisitions typically include over 70% percent proved producing reserves and a high percentage of proven reserves, minimizing the possibility of negative reserve revisions;
- Our due diligence with respect to acquisitions is one of the most rigorous in the industry; and
- Our insurance levels and premiums are continuously reviewed and managed.

Environment & Safety Risk Management



Enerplus is committed to its goal of conducting business in a safe and environmentally responsible manner. Emphasis is focused on providing the best possible protection and safety to employees, the public, stakeholders and the environment. Enerplus' comprehensive Environment and Safety Management Program is constantly reviewed and upgraded to meet this commitment. In 2002, Enerplus registered its existing E&S Management Program with the Canadian Association of Petroleum Producers (CAPP) Environment Health and Safety Stewardship Program at the Platinum level, the highest attainable rating, which reflects our standards within the industry. This program includes the following initiatives:

- Reduced or eliminated flaring and greenhouse gas emissions through vapour recovery installations, gas plant enhancements and improved flare technology;
- Utilized our Corrosion Risk Management Program to help identify properties where improvements have a positive impact, resulting in pipeline replacements, installation of pipeline liners, and improved corrosion protection programs;
- Maintained an active abandonment and reclamation program dedicated to decommissioning unneeded facilities and restoring these lease sites to their original state as well as an active idle wellbore abandonment program;
- Maintained our Job Performance Management System (JPMS) as a comprehensive approach to managing risk training and worker competencies to ensure that hazardous tasks are carried out safely, responsibly, and effectively; and
- Provided an internal Loss Control Council (LCC), a rotating team of experienced and knowledgeable employees consisting of both field and office staff, to conduct inspections of operated properties each year to ensure the highest standards are maintained.

Financial Risk Management

Enerplus has a commodity price risk management program that is designed to provide price protection on a portion of its future production. The program establishes hedge positions on future crude oil and natural gas prices in an effort to:

- Protect against adverse commodity price movements;
- Retain significant exposure to upside price movements;
- Lock in economics for development programs;
- Lock in the accretion for acquisitions; and
- Provide a measure of stability for the Fund's cash flow.

Other financial risk management efforts also include interest rate hedging as well as diversification of debt and equity sources in both Canada and the United States. Details of our financial risk management positions are outlined in the MD&A and financial statements.

The following discussion and analysis of financial results is to be read in conjunction with the audited consolidated financial statements as at and for the years ended December 31, 2002 and 2001 and is based on information available to March 6, 2003. All amounts are stated in Canadian dollars unless otherwise specified.

Important Information Regarding Comparative Financial Statements

On June 21, 2001, the respective unitholders of EnerMark Income Fund ("EnerMark") and Enerplus Resources Fund ("Enerplus") approved a merger ("Merger") combining the two Funds. As the former unitholders of EnerMark held approximately 69% of the outstanding trust units of the combined Fund at the date of acquisition, the Merger has been accounted for using the reverse takeover method of accounting for business combinations. For accounting purposes, EnerMark acquired Enerplus effective June 21, 2001 and continued as Enerplus Resources Fund ("Enerplus" or the "Fund").

As a result of the reverse takeover method of accounting, the audited consolidated financial statements for the year ended December 31, 2001 presented herein include only EnerMark's operating results prior to the Merger with Enerplus on June 21, 2001 and include the results of the merged Fund thereafter. All comparative figures and references to prior years are those of EnerMark. Thus, unless otherwise indicated, all historical production, reserve and other operational information is based on the historical operations of EnerMark. The production, reserve and other operational information attributable to the operations of Enerplus as it existed prior to the Merger has only been included since June 21, 2001. This discussion, analysis and information has been restated, as applicable, to reflect the trust unit exchange ratio of 1.000 EnerMark trust unit for 0.173 of an Enerplus trust unit, pursuant to the Merger.

Critical Accounting Policies

The financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). A summary of significant accounting policies is presented in Note 1 to the consolidated financial statements. A reconciliation of differences between Canadian and United States GAAP is presented in Note 10 to the consolidated financial statements. Certain accounting policies are critical to understanding the financial condition and results of operations of Enerplus. Most accounting policies are mandated under GAAP and management does not have the ability to select alternatives. However, in accounting for oil and gas activities, management has a choice between two acceptable accounting policies: the full cost and the successful effort methods of accounting.

The Fund follows the full cost method of accounting for oil and natural gas activities, as described in Note 1 to the consolidated financial statements. Using the full cost method of accounting, all costs of acquiring, exploring and developing oil and natural gas properties are capitalized, including unsuccessful drilling costs and administrative costs associated with acquisitions and development. Under the successful efforts method of accounting, all exploration costs, except costs associated with drilling successful exploration wells, are expensed in the period in which they are incurred. The difference between these two methodologies is not expected to be significant to the Fund's net income or net income per unit as the Fund participates in low risk development drilling that has traditionally achieved high success rates.

Under the Fund's full cost method of accounting, costs are aggregated on a country by country basis. The ceiling test is applied to the overall carrying value of the property, plant and equipment for a Canada-wide cost centre with the reserves valued using constant dollar prices at period end. The Fund has one cost centre as operations are currently conducted only in Canada. Under the successful efforts method of accounting, the costs are aggregated on a property by property basis. The carrying value of each property is subject to an impairment test by determining the fair value of the reserves based on estimates of future prices at period end. As each accounting methodology uses a different commodity price assumption and calculates impairment differently, each policy may generate a different net income and a different carrying value of property plant and equipment, depending on the circumstances at period end.

Use of Estimates

The preparation of financial statements in accordance with GAAP requires management to make certain judgements and estimates, some of which may relate to matters that are uncertain. Changes in these judgements and estimates could have a material impact on the Fund's financial results and financial condition. The Fund has determined that the process of estimating reserves is critical to several accounting estimates. The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices, operating costs, and royalty burdens change. Reserve estimates impact net income through depletion, provision for site restoration and in the application of the ceiling test whereby the value of the oil and gas assets are subjected to an impairment test. The reserve estimates are also used to assess the borrowing base for the Fund's credit facilities. Revisions or changes in the reserve estimates can have either a positive or a negative impact on net income or the borrowing base of the Fund.

Recent Canadian Accounting Pronouncements

In November 2002, the Canadian Institute of Chartered Accountants ("CICA") amended its accounting guideline on hedging relationships, which was originally issued in November 2001. The guideline establishes certain conditions where hedge accounting may be applied. It is effective for years beginning on or after July 1, 2003. The guideline will have a significant impact to the Fund's net income and net income per trust unit, as the 3-way option contracts for oil and natural gas as described in Note 7 to the consolidated financial statements will not qualify for hedge accounting. Where hedge accounting does not apply, any changes in the mark-to-market values of the option contracts relating to a period can either reduce or increase net income and net income per trust unit for that period. The Fund expects to adopt this standard January 1, 2004.

In December 2002, the CICA issued a new standard on the accounting for asset retirement obligations. This standard requires recognition of a liability for the future retirement obligations associated with property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The new standard is effective for all fiscal years beginning on or after January 1, 2004. The Fund expects to adopt this standard January 1, 2004. The impact of the effect of this new standard on the consolidated financial statements has not been determined. The Fund currently provides future asset retirement obligations using the unit-of-production method and is included in depletion, depreciation and amortization expense. Actual site restoration costs are charged against the accumulated liability.

Other accounting standards issued by the CICA during the year ended December 31, 2002 are not expected to materially impact the Fund.

2002 Highlights

- With respect to fiscal 2002, Enerplus paid $246.8 million to unitholders ($3.32 per trust unit) or 85% of funds flow from operations and retained $46.3 million ($0.62 per trust unit) for debt reduction.
- Enerplus diversified its debt portfolio by repaying a portion of its bank debt with the proceeds raised through the issuance of US$175 million 12-year senior unsecured notes.
- During the year, the Fund replaced 181% of its production through acquisitions and development.

- The Fund successfully maintained production volumes throughout the year with average daily volumes of 62,784 BOE while achieving a decrease in operating expenses of $0.23/BOE from $6.09/BOE to $5.86/BOE.
- Enerplus continued with its active development program, investing $141.7 million in development drilling and facility enhancements for 2002, drilling 300 net wells with a 99% success rate.
- Enerplus acquired working interests in various oil and gas properties for $60.6 million. The major property acquisitions include an incremental working interest in the Medicine Hat Glauc. "C" operated property for consideration of $20.5 million and the acquisition of a 16% working interest in Oil Sands Lease #24 (also known as the Joslyn Creek Lease) for $16.4 million.
- On September 12, 2002 the Fund successfully closed an equity offering of 4,750,000 trust units at a price of $26.85 per trust unit for gross proceeds of $127.5 million ($120.9 million net of issuance costs).
- On October 21, 2002 Enerplus completed the acquisition of Celsius Energy Resources Ltd. for $161.4 million.
- During the fourth quarter 2002, the Fund successfully completed a cross-border equity offering of 7,959,300 trust units at a price of $26.00 per trust unit for gross proceeds of $206.9 million ($193.7 million net of issuance costs).
- Subsequent to December 31, 2002, Enerplus closed the acquisition of PCC Energy Inc. and PCC Energy Corp (collectively "PCC") for a total consideration of $167.6 million.

Results of Operations

Production

In accordance with Canadian practice, production volumes, reserve volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise indicated.

Daily production during 2002 averaged 62,784 BOE/day, representing a 16% increase over average production volumes of 54,015 BOE/day for the previous year. Although the majority of this increase was a result of the Merger, acquisitions completed during the year accounted for annualized production of 1,900 BOE/day primarily from the addition of Celsius Energy Resources Ltd. ("Celsius") which closed on October 21, 2002 and the additional interest of the Medicine Hat Glauc "C" property which closed in March 2002. Enerplus' production before acquisitions was on target with expectations for the year. The Fund will see the full impact of these acquisitions in 2003.

Enerplus' production is widely distributed across more than 250 properties in Alberta, Saskatchewan and British Columbia. The largest 10 properties account for 31% of Enerplus' production. This wide distribution minimizes the risk that production might be materially impacted by the performance of a few major properties.

Average production volumes for the years ended December 31, 2002 and 2001 are outlined below:

Daily Production Volumes	2002	2001 [1]	% Change
Natural gas (Mcf/day)	**210,517**	176,671	19
Crude oil (bbls/day)	**23,288**	20,592	13
Natural gas liquids (bbls/day)	**4,410**	3,978	11
Total daily sales (BOE/day)	**62,784**	54,015	16

[1] *2001 production reflects only 193 days of the post-merger Enerplus production after the date of the Merger.*

Enerplus' exit production rate averaged 67,800 BOE/day for the month of December 2002, with a weighting of 58% natural gas, 36% crude oil, and 6% natural gas liquids. Production is expected to average 68,900 BOE per day in 2003, assuming capital development spending of approximately $155 million, but without taking into account any further acquisitions. This production estimate is based on a full year benefit of the Celsius acquisition and the PCC acquisition from the closing date of March 5, 2003.

Pricing and Price Risk Management

The average price that Enerplus received for its natural gas (before hedging) decreased 21% from $4.91/Mcf in 2001 to $3.87/Mcf in 2002. In comparison, the AECO Monthly Index decreased 35% from $6.30/Mcf in 2001 to $4.07/Mcf in 2002 and the NYMEX Henry Hub index price decreased 26% from US$4.38/Mcf in 2001 to US$3.25/Mcf in 2002. The Fund has a balanced natural gas portfolio of spot and term contracts that will respond differently to the market than the reference indices. The wider basis differential between the AECO and NYMEX indices, the strengthening Canadian dollar, and the physical fixed price contracts helped reduce the Fund's exposure to price volatility.

The average price that Enerplus received for its crude oil (before hedging) increased 13% from $30.48/bbl in 2001 to $34.37/bbl in 2002. Although there was virtually no change in the average price of benchmark West Texas Intermediate ("WTI") crude oil from US$25.97 in 2001 to US$26.08 in 2002, Enerplus realized the benefit from a narrowing in the price differentials on it's heavier streams of crude oil during the year and a slightly weaker Canadian dollar.

The realized prices for natural gas liquids ("NGLs") decreased 17% from $31.12/bbl in 2001 to $25.68/bbl during 2002. These prices tend to be influenced by the corresponding prices for natural gas.

Average Selling Price *(before the effects of hedging)*	2002	2001	% Change
Natural gas (per Mcf)	$ 3.87	$ 4.91	-21
Crude oil (per bbl)	34.37	30.48	13
Natural gas liquids (per bbl)	25.68	31.12	-17
Per BOE	$ 27.49	$ 29.89	-8

Average Benchmark Pricing	2002	2001	% Change
AECO natural gas (per Mcf)	$ 4.07	$ 6.30	-35
NYMEX natural gas (US$ per Mcf)	3.25	4.38	-26
WTI crude oil (US$ per bbl)	26.08	25.97	0
CDN$/US$ exchange rate	$ 0.6369	$ 0.6458	-1

Enerplus has an on-going commodity price risk management program that is designed to provide price protection on a portion of its future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. The program is intended to provide a measure of stability to the Fund's cash distributions as well as ensure Enerplus realizes positive economic returns from its capital development and acquisition activities.

In 2002, Enerplus realized a cost of $8.7 million compared to a $50.1 million gain in 2001 as a result of its price risk management program, as outlined on next page:

Gain (Cost) from Financial Hedging

($ millions except per unit amounts)	2002		2001	
Crude oil	$ (4.3)	$(0.50)/bbl	$ 5.5	$ 0.73/bbl
Natural gas	(4.4)	$(0.06)/Mcf	44.6	$ 0.69/Mcf
Net hedging gain (cost)	$ (8.7)	$(0.38)/BOE	$ 50.1	$ 2.54/BOE

During the first half of 2001, Enerplus was able to hedge a portion of its production for the remainder of the year at favourable rates. When natural gas prices retreated from their record highs at the end of 2001, Enerplus' hedging protection resulted in a significant gain. Hedging costs arose in 2002 as oil and natural gas prices strengthened through to the end of the year due to colder winter temperatures, a crude oil production strike in Venezuela, and the threat of hostilities in the Middle East.

Enerplus' commodity risk management position as at December 31, 2002 is described in Note 7 to the consolidated financial statements. Commodity price risk is managed through fixed price physical delivery contracts and financial instruments such as forward contracts. The net receipts or payments arising from the forward contracts are recognized in income as a component of oil and gas sales during the same period as the corresponding hedged position. At December 31, 2002, Enerplus had $1.7 million in unamortized premium costs related to forward contracts that will be amortized over the remaining life of those contracts. The mark-to-market value of the financial forward contracts at December 31, 2002 represented an unrealized cost of $34.2 million on natural gas and an unrealized cost of $8.5 million on oil with reference to year-end prices and forward markets.

In the future, Enerplus intends to continue to manage its commodity price exposure in a similar manner as in the past with the objective of establishing downside price protection at a reasonable cost, while maintaining exposure to improving prices. The future gain or cost from such a program depends on forward markets and future prices.

Enerplus has the following physical and financial contracts in place:

Physical & Financial	Contracted natural gas volumes MMcf/day	% of estimated gross natural gas production	Contracted crude oil volumes bbls/day	% of estimated gross crude oil production
First half 2003	104.5	42	11,000	46
Second half 2003	103.4	41	12,000	50
First half 2004	70.3	28	8,500	36
Second half 2004	50.0	20	5,000	21

Even with these positions, the Fund's cash flow remains sensitive to changes in commodity prices as demonstrated by the following table:

Sensitivity to Changes in Price and Exchange Rate	Estimated Effect on 2003 Distributions per Trust Unit
Change of $0.10 per Mcf in the price of natural gas	$0.05
Change of US$1.00 per barrel in the price of WTI crude oil	$0.10
Change of 1,000 BOE/day in production	$0.08
Change of $0.01 in the US$/CDN$ exchange rate	$0.04
Change of 1% in interest rate	$0.03

These sensitivities are based on current projections for 2003, which have been adjusted to include all commodity contracts as described in Note 7 to the consolidated financial statements. They apply to commodity prices, production, interest and exchange rates within the context of current market rates and the Fund's current risk management positions.

To the extent the market price of crude oil or natural gas change to levels that are above the ceiling or below the floor price limits set by existing commodity contracts, the above sensitivities will no longer be relevant. As these sensitivity calculations assume a number of factors, actual sensitivities may vary significantly from those presented.

Revenues

Crude oil and natural gas revenues, inclusive of hedging, were $621.5 million for the year ended December 31, 2002, which was marginally lower than the $639.4 million reported for the year ended December 31, 2001. Revenues in 2002 represent a full year's production compared to the partial year's production received in 2001, due to the Merger. The increase in revenues from greater production volumes was more than offset by the combined effects of the variance in hedging results and the overall decrease in natural gas and NGL prices during 2002 compared to 2001. These variances are described in the table below.

Analysis of Sales Revenues *($ millions)*

	Crude Oil	NGL	Natural Gas	Total
2001 Sales Revenues	$ 234.5	$ 45.2	$ 359.7	$ 639.4
Price variance	33.1	(8.8)	(79.9)	(55.6)
Volume variance	30.0	4.9	61.6	96.5
Hedging variance	(9.7)		(49.1)	(58.8)
2002 Sales Revenues	**$ 287.9**	**$ 41.3**	**$ 292.3**	**$ 621.5**

Royalties

Royalties decreased marginally from $132.7 million or 22.5% of oil and gas sales before hedging for 2001 to $131.8 million or 20.9% for 2002. The decline in royalties as a percentage of oil and gas sales before hedging is attributable to a lower reference natural gas price used by the provincial government to calculate crown royalties during the year, which is consistent with the decrease in realized natural gas prices during the year. In the current commodity price environment, Enerplus expects the royalty percentage to remain at approximately 21%.

Operating Expenses

Operating expenses for the year ended December 31, 2002 increased to $134.4 million from $120.1 million in 2001 due to higher production volumes associated with acquisitions and the Merger. On a per unit of production basis, operating expenses decreased by 4% from $6.09/BOE in 2001 to $5.86/BOE in 2002. Several cost categories that decreased year over year include water disposal costs, utility costs and the cost of supplies and services. Prior period adjustments to processing income also contributed to the overall reduction in operating expenses. Enerplus expects to maintain a similar level of operating costs in 2003 and average approximately $5.85/BOE.

General and Administrative Expenses

General and administrative expenses were $16.0 million or $0.70 per BOE for the year ended December 31, 2002 compared to $13.0 million or $0.66 per BOE for 2001. General and administrative costs per BOE of production increased due to the relocation of the corporate head office combined with the incremental cost of consulting services retained to optimize cash flows and pursue value creation opportunities within the existing property portfolio. Enerplus expects general and administrative costs to be approximately $0.70/BOE for 2003. As allowed under the full cost method of accounting, Enerplus capitalized $9.1 million of general and administrative costs in 2002 compared to $7.5 million in 2001. The majority of these capitalized costs represent compensation costs for staff involved in development and acquisition activities.

Management Fees

Management Fees *($ millions)*	2002	2001
Base management fee	$ 9.2	$ 9.3
Performance fee	12.4	–
Total management fees	$ 21.6	$ 9.3

Enerplus Global Energy Management Company ("EGEM") supplies management services to Enerplus on a fee and cost reimbursement basis. The management fees, which were renegotiated as a result of the Merger, are now comprised of two components, a base management fee of 2.75% of net operating income and an incremental performance fee which can range from 0% to 4% of net operating income.

For the year ended December 31, 2002 total management fees were $21.6 million compared to $9.3 million for 2001. The performance fee, which is based on the Fund's total return and its relative performance compared to other senior conventional oil and gas trusts, was $12.4 million or 3.5% of the Fund's net operating income for 2002. This performance fee was based on the Fund earning a total return of approximately 29% for unitholders and placing second out of the eight senior conventional oil and gas trusts for total return in its peer group. This return was calculated using the ten day weighted average trading price of the trust units prior to December 31, 2002 and 2001. There was no performance fee recorded for 2001 pursuant to the terms of the management agreement as the Manager received a minimum fee of 172,500 trust units with an assigned value of $5,000,000 in conjunction with the Merger. This fee was accounted for as a cost of the Merger.

On March 6, 2003, the Fund announced plans to internalize its management structure by acquiring the shares of the management company, EGEM, from an indirect subsidiary of El Paso Corporation ("El Paso"). The proposed internalization transaction will result in the elimination of all management fees effective April 23, 2003. Enerplus' unitholders will be asked to approve the transaction at the annual general and special meeting to be held on April 23, 2003.

Under the terms of the proposed transaction, Enerplus will purchase EGEM for total cash consideration of approximately $48.9 million. Furthermore, El Paso has agreed to fix the management fees for the period from January 1, 2003 to April 23, 2003 in an amount of $3.2 million.

Retention arrangements, at a maximum cost of $4.7 million to the Fund, have been made for the executive team and staff at Enerplus to ensure continuity.

The expected benefits of the proposed internalization transaction are as follows:

- The transaction cost represents fair value to unitholders relative to the management fees that have been paid in the past, the estimated future management fees, and the costs associated with terminating the existing agreement;
- The transaction is immediately accretive to Enerplus' net asset value and cash flow per trust unit;
- The transaction compares favorably in relation to other internalization transactions that have occurred in the energy trust sector;
- In conjunction with the transaction, Enerplus has taken steps to affirm the continued commitment of the executive;
- The Fund's organizational structure will be simplified and its corporate governance will be improved. For example, unitholders will be able to elect all nine members of the board of directors rather than just the six independent directors, as EGEM's right to nominate three directors will be eliminated;
- The transaction may lower Enerplus' cost of capital by increasing the attractiveness of Enerplus trust units to a wider range of investors, including institutions that have refrained from purchasing entities with external management contracts;

- Furthermore, by eliminating management fees, Enerplus can be more competitive with respect to future acquisitions and consolidation opportunities within the trust and E&P sectors.

Interest Expense

Interest expense increased to $18.3 million in 2002 from $17.6 million in 2001 as a result of higher average debt outstanding throughout 2002.

As at December 31, 2002, Enerplus' long-term debt was effectively structured to consist of $268.3 million of floating rate and $75.0 million of fixed rate debt. Concurrent with the issuance of the US$175.0 million, 6.62% fixed rate senior unsecured notes, Enerplus swapped the proceeds for CDN$268.3 million with interest based on floating rate three month Canadian banker's acceptances, plus 1.18% (See Note 2 to the consolidated financial statements). In addition, the Fund entered into three year fixed interest rate swaps on CDN$75 million as more fully described in Note 7 to the consolidated financial statements.

Depletion, Depreciation and Amortization

Depletion of property, plant and equipment is provided using the unit-of-production method based on constant price proven reserves. An estimate of the future costs for restoration and abandonment of well sites and facilities is updated annually and this cost estimate is amortized over the life of the properties on a unit-of-production basis as part of depletion, depreciation and amortization expense ("DD&A").

DD&A increased to $213.9 million or $9.33/BOE in 2002 from $194.1 million or $9.85/BOE in 2001. Higher production volumes during 2002 have increased the total amount of DD&A however, on a BOE basis, DD&A has decreased.

Enerplus places a limit on the carrying value of property, plant and equipment (the "ceiling test"). The cost of these assets less accumulated depletion, accumulated site restoration and future income taxes is limited to the estimated future net revenue from proved reserves (based on unescalated prices and costs at the balance sheet date) less estimated future general and administrative costs, financing costs, management fees and income taxes. The ceiling test at December 31, 2002 was calculated using the December 31 closing WTI price of US$31.20/bbl and AECO spot price of $4.79/Mcf (2001 - WTI US$19.84/bbl and AECO spot $3.75/Mcf). In both 2002 and 2001 the ceiling test resulted in a surplus and accordingly there was no additional charge to DD&A.

Taxes

Capital taxes, which are based on total debt and equity levels of the Fund's operating companies at the end of the year, increased to $5.5 million for 2002 from $4.7 million in 2001 primarily due to the increase in the Fund's capital during 2002. According to the February 2003 Federal Budget, capital taxes are to be gradually eliminated over the next five years.

Future income taxes arise from differences between the accounting and tax bases of the operating companies' assets and liabilities. In the Fund's structure, payments are made between the operating companies and the Fund transferring both income and future income tax liability to the unitholders. Therefore, it is the opinion of management that no cash income taxes are expected to be paid by the operating companies in the future, and as such, the future income tax liability recorded on the balance sheet will be recovered through earnings over time. For the year ended December 31, 2002, a future income tax recovery of $35.4 million ($31.5 million on 2001) was recorded in income.

Upon the acquisition of Celsius, a future income tax liability of $42.1 million was recorded. This liability arose as the purchase price of Celsius' assets exceeded the balance of its tax pools at the date of the acquisition.

Netbacks

Netbacks per BOE of Production (6:1)	2002	2001
Production per day	62,784	54,015
Weighted average price (net of hedging)	$ 27.11	$ 32.43
Royalties, net of ARTC	(5.75)	(6.73)
Operating costs	(5.86)	(6.09)
Operating netback	15.50	19.61
General and administrative	(0.70)	(0.66)
Management fees	(0.94)	(0.47)
Interest expense, net of interest and other income	(0.78)	(0.85)
Capital taxes	(0.23)	(0.24)
Restoration and abandonment cash costs	(0.20)	(0.13)
Funds flow from operations	12.65	17.26
Depletion and depreciation	(9.07)	(9.18)
Amortization of site restoration and hedging, net of cash costs	(0.06)	(0.54)
Future income tax recovery	1.54	1.60
Net income per BOE of production	$ 5.06	$ 9.14

Net Income and Funds Flow From Operations

Net income for the year ended December 31, 2002 was $115.9 million, or $1.61 per trust unit, down 36% (51% per trust unit) from $180.3 million or $3.28 per trust unit for 2001. After adding back non-cash expenses such as depletion, depreciation and amortization and the future income tax recovery, the resultant funds flow from operations was $289.9 million in 2002 or $4.03 per trust unit compared to $340.2 million or $6.20 per trust unit in 2001. This decrease in net income and funds flow from operations is mainly due to the reduction in natural gas prices and the difference between the $50.1 million gain recognized from crude oil and natural gas hedging contracts during 2001 compared to a hedging cost of $8.7 million in 2002.

Quarterly Financial Information

($ millions, except per trust unit amounts)

	Oil and Gas Revenue Net of Royalties	Net Income	Net income per trust unit Basic	Net income per trust unit Diluted
2002				
First quarter	$ 97.0	$ 9.4	$ 0.13	$ 0.13
Second quarter	120.6	26.0	0.37	0.37
Third quarter	122.3	29.1	0.41	0.41
Fourth quarter	149.7	51.4	0.66	0.66
Total	$ 489.6	$ 115.9	$ 1.61	$ 1.61
2001				
First quarter	$ 136.7	$ 59.7	$ 1.42	$ 1.41
Second quarter	109.3	58.5	1.30	1.29
Third quarter	130.9	25.1	0.39	0.39
Fourth quarter	129.8	37.0	0.55	0.55
Total	$ 506.7	$ 180.3	$ 3.28	$ 3.28

Cash Available for Distribution

Enerplus makes monthly cash distributions to its unitholders based upon the net cash flow from its oil and gas operations. A portion of this cash flow is typically withheld to repay bank debt incurred with respect to acquisitions and capital spending. For the year ended December 31, 2002, Enerplus generated $289.9 million in funds flow from operations. Of this amount (together with certain funds described in the following table), $246.8 million ($3.32 per trust unit) was paid to unitholders and $46.3 million ($0.62 per trust unit) was retained for debt reduction.

Management monitors the Fund's distribution payout policy with respect to forecasted cash flows, debt levels, and spending plans. The level of cash retained for debt repayment typically varies between 10% and 20% of annual cash flow, although management is prepared to adjust the payout levels in an effort to balance the investor's desire for distributions with the Fund's requirement to maintain a prudent capital structure.

The following table reconciles Enerplus' "Funds Flow from Operations" with the cash available for distribution to unitholders.

Reconciliation of Cash Available for Distribution

($ millions, except per trust unit amounts)	2002	2001
Funds flow from operations	**$ 289.9**	$340.2
Cash withheld for debt reduction	**(46.3)**	(46.2)
Enerplus cash flows *(Note A)*	-	16.9
Accruals *(Note B)*	**3.2**	5.6
Cash available for distribution *(Note C)*	**$ 246.8**	$316.5
Cash available for distribution per trust unit	**$ 3.32**	$ 5.67

Note A: As a result of the Merger, funds flow from operations do not include funds earned by the former Enerplus prior to June 21, 2001. However, cash distributions include the July and August 2001 payments in respect of these funds. As a result, the July and August 2001 payments to unitholders are added to funds flow from operations for purposes of this reconciliation.

Note B: According to the current Royalty Agreement with Enerplus Resources Corporation ("ERC"), the royalty paid to the Fund must be on a cash basis. As a consequence, the change in the accrued net revenues of ERC for the year are added back to funds flow from operations for purposes of this reconciliation. Subsequent to December 31, 2002 the Fund amended the royalty agreement with ERC to allow for the royalty to be paid on an accrued basis.

Note C: The cash available for distribution of $246.8 million in 2002 can be reconciled to the cash paid to unitholders of $233.6 million in the consolidated statement of cash flows by subtracting the January and February 2003 payments to unitholders and adding the January and February 2002 payments to unitholders, as the Consolidated Statement of Cash Flows reflects cash payments to unitholders during the calendar year.

Capital Expenditures

During the year ended December 31, 2002, Enerplus spent $361.7 million compared to $874.4 million in 2001, on capital expenditures and acquisitions net of divestitures. Enerplus finances its capital expenditures through bank borrowing, new equity issues, and by withholding a portion of cash otherwise available for distribution.

Capital Expenditures *($ millions)*	2002	2001
Development expenditures	$ 94.9	$ 87.9
Plant and facilities	46.8	53.6
Sub-total	141.7	141.5
Office	4.4	1.8
Sub-total	146.1	143.3
Acquisitions of oil and gas properties	60.6	77.4
Corporate acquisitions	158.1	722.2
Dispositions of oil and gas properties	(3.1)	(68.5)
Total Net Capital Expenditures	$ 361.7	$874.4
Established reserves (MMBOE):		
Net change in established reserves after production	18.1	102.2
Annual production	22.9	19.7
Annual established reserve additions	41.0	121.9
Finding, development and acquisition costs ($/BOE):	$ 8.82	$ 7.17

Finding, development and acquisition ("FD&A") costs based on established reserves for the year were $8.82/BOE compared to $7.17/BOE for 2001. The increase in FD&A costs reflect higher prices paid for acquisitions (in an environment of increased oil and gas price expectations); a focus on natural gas acquisitions (which typically trade at a higher FD&A cost due to the attractive economics of natural gas); and the inclusion of Oil Sands Lease #24 (which is a long-term investment with no current production or established reserve value).

Capital Expenditures by Major Property *($ millions)*	2002	2001
Joarcam	$ 22.0	$ 5.1
Medicine Hat	13.3	13.1
Hanna/Garden Plains	12.9	26.5
Bantry	6.3	10.6
Verger	6.0	1.3
Mount Benjamin	5.7	6.1
Other	75.5	78.8
Total	$ 141.7	$ 141.5

Enerplus is forecasting capital expenditures of approximately $155 million in 2003 on existing properties. A total of $95 million or 61% is expected to be invested in development drilling on natural gas projects at Countess, Verger, Bantry, Medicine Hat, Hanna Garden and other areas. In addition to the development drilling on these properties, a number of wells will be restimulated in the Medicine Hat, Bantry and Verger areas to improve natural gas productivity.

A total of $45 million is expected to be invested in further development of the oil properties at Progress, Valhalla, Joarcam, Giltedge, Silver Heights and Cadogan. In addition, Enerplus expects to spend $7 million to develop a steam assisted gravity drainage pilot on the Oil Sands Lease #24 north of Fort McMurray. Enerplus also expects to spend approximately $8 million on land and seismic.

Enerplus routinely evaluates its property portfolio and disposes of properties that are viewed as non-core holdings with limited contribution to cash flow or upside development potential. In 2002, Enerplus sold $3.1 million worth of non-core oil and gas properties. Enerplus expects to continue its process of rationalizing marginal properties and acquiring new properties in 2003.

Liquidity and Capital Resources

Long-term debt at December 31, 2002 was $361.7 million, which includes $93.4 million of bank indebtedness and $268.3 million of senior unsecured notes. Although the Fund's investing activities were higher than 2001 primarily due to the acquisition of Celsius Energy Ltd., long-term debt was reduced by the end of the year with net proceeds from the issue of 13.3 million trust units combined with cash from operations that has been withheld for debt repayments.

During 2002, Enerplus diversified its debt portfolio through the issuance of US$175.0 million senior, unsecured notes with a coupon rate of 6.62% priced at par (the "Notes"). The Notes have a final maturity of June 19, 2014, with amortizing payments of 20% per annum on each of the five anniversary dates commencing on June 19, 2010. Concurrent with the issuance of the Notes, Enerplus swapped the US$175.0 million into Canadian dollar denominated floating rate debt at an exchange rate of 1.5333 for gross proceeds of $268.3 million at a floating interest rate, based on Canadian three month banker's acceptances, plus 1.18%. This cross currency swap on the senior unsecured notes represented a mark-to-market gain of $37.1 million at December 31, 2002.

On November 7, 2002 the Fund's $620 million borrowing base with respect to its bank credit facilities and senior unsecured notes increased to $700 million resulting in the bank credit facilities increasing by $80 million from $351.7 million to $431.7 million. The limit is based on the bank's evaluation of the value of Enerplus' proven oil and gas reserves and reflected the additional values attributable to acquisitions completed during the year.

Enerplus plans to finance future commitments with a combination of cash flow from operations, debt, and equity raised in the Canadian and U.S. markets.

Key financial ratio's for the year were as follows:

Financial Leverage and Coverage	2002	2001
Long-term debt to EBITDA [1]	1.1x	1.2x
Funds flow from operations to interest expense	15.8	19.3x
Debt to debt plus equity	19%	23%

[1] *EBIDTA is provided to assist investors in determining the ability of the Fund to generate cash from operations. It is calculated from the consolidated statement of income as revenue less operating expenses, general and administrative expenses, and management fees. This measure does not have any standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities.*

Commitments

Enerplus has contracted to transport 10MMcf/day of natural gas into Chicago on the Foothills and Northern Border pipelines until October 31, 2008. It has also agreed to transport 5 MMcf/day to Marshfield, Illinois on the TransCanada and Viking pipelines until October 31, 2008. In addition, Enerplus has pipeline commitments to transport 5 MMcf/day into Chicago on Alliance Pipeline until October 31, 2015. These contracts apply to 10% of Enerplus' total natural gas production.

Enerplus must continue to pay crown royalties, surface rentals and mineral taxes with respect to its ongoing ownership of hydrocarbon production rights. The amounts paid with respect of these burdens will depend on the future ownership, production, prices and legislative environment at the time.

Trust Unit Information

Enerplus had 82,898,000 trust units outstanding at December 31, 2002 compared to 69,532,000 trust units at December 31, 2001. The weighted average basic number of trust units outstanding during 2002 was 71,946,000 (2001 - 54,907,000).

Income Taxes

The following sets out a general discussion of the Canadian and U.S. tax consequences of holding Enerplus trust units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Unitholders or potential unitholders should consult their own legal or tax advisors as to their particular tax consequences.

Canadian Taxpayers

The Fund qualifies as a mutual fund trust under the Income Tax Act (Canada) and, accordingly, trust units of the Fund are qualified investments for RRSPs, RRIFs, RESPs, and DPSPs. Each year, the Fund is required to file an income tax return and any taxable income in the Fund is allocated to the unitholders.

Unitholders are required to include in computing income their pro-rata share of any taxable income earned by the Fund in that year. An investor's adjusted cost base ("ACB") in a trust unit equals the purchase price of the trust unit less any non-taxable cash distributions received from the date of acquisition. To the extent a unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholder's ACB will be brought to $nil.

Enerplus paid $3.25 per trust unit in cash distributions to unitholders during the 2002 calendar year. For Canadian tax purposes, 34% of these distributions, or $1.10 per trust unit was a tax deferred return of capital, 64% or $2.09 per trust unit was taxable to unitholders as other income, and 2% or $0.06 per trust unit was taxable dividend income.

U.S. Taxpayers

U.S. unitholders who receive cash distributions are subject to a 15% Canadian withholding tax, applied to the taxable portion of the distribution as computed under Canadian tax law. U.S. taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

The taxable portion of the cash distribution for U.S. tax purposes is determined by Enerplus in relation to its current and accumulated earnings and profits using U.S. income tax principles. The taxable portion so determined is considered to be a dividend for U.S. tax purposes.

The non-taxable portion of the cash distribution, is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss arising from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as gains.

Enerplus paid US$2.07 per trust unit to U.S. residents during the 2002 calendar year, of which 28% or US$0.57 per trust unit was a tax deferred return of capital and 72% or US$1.50 per unit was a taxable dividend.

Risk Factors and Risk Management

Investors that purchase Enerplus trust units are participating in the net cash flow from a portfolio of western Canadian crude oil and natural gas producing properties. As such, the cash flow paid to investors and the value of Enerplus units are subject to numerous risk factors. These risk factors, many of which are associated with the oil and gas industry, include, but are not limited to, the following influences that could affect the Fund's future results:

Commodity Price Risk

The Fund has exposure to movements in oil and natural gas prices that could have a material adverse effect on Enerplus' results of operations and financial condition which, in turn, could affect the market price of the trust units and the amount of distributions to unitholders. Oil and natural gas prices may fluctuate in response to a variety of factors including global and domestic economic conditions, weather conditions, the supply and price of imported oil and liquified natural gas, the production and storage levels of North American natural gas, political stability, the proximity of reserves to and capacity of transportation facilities, the price and availability of alternative fuels, and government regulations.

Enerplus uses financial derivative instruments and other hedging mechanisms to limit a portion of the adverse effects resulting from volatility in natural gas and oil commodity prices while retaining exposure to upside price movements. To the extent commodity price exposure is hedged, the benefits that would otherwise be experienced if commodity prices were to increase may be forgone. In addition, the commodity hedging activities could expose the Fund to losses.

Operational Risk

The value of Enerplus trust units is based on the underlying value of the oil and gas reserves. Geological and operational risks can affect the quantity and quality of reserves and the cost of ultimately recovering those reserves. Lower oil and natural gas prices may increase the risk of write-downs of Enerplus' oil and gas property investments. Higher operating costs may be difficult to control as increased activity in the oil and gas industry may increase the cost of goods and services and make it difficult to hire and retain staff which may decrease the amount of cash flow received by the Fund and therefore, reduce distributions to unitholders.

Enerplus strives to acquire low risk, mature properties with a high proportion of proven reserves, high cash netbacks, long reserve lives, and predictable production. Similarly, Enerplus participates in lower-risk development projects, while farming out or monetizing higher risk exploratory prospects.

Each year a significant portion of Enerplus' proven and probable oil and gas reserves are evaluated by a firm of independent reservoir engineers. Approximately 84% of the net present value of the total established reserves discounted at 12% were evaluated at December 31, 2002. The Environment, Safety and Reserves Committee has reviewed and approved the reserve report.

Enerplus maintains certain insurance coverages related to liability and property exposures.

Enerplus offers competitive incentive-based compensation packages to attract and retain qualified staff.

Reserves Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Enerplus' ability to replace production depends on its success in acquiring new reserves and developing existing reserves. Acquisition of oil and gas assets depend on Enerplus' assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to unitholders and the value of the trust units.

Acquisitions are subject to stringent investment criteria, due diligence, and review. Acquisitions exceeding $10 million require approval by the Board of Directors. Independent reservoir engineers evaluations are required for acquisitions in excess of $5 million.

Access to Capital Markets

Since Enerplus distributes the majority of its net cash flow to unitholders, it must finance a large portion of its acquisition and development activity through continued access to the equity and debt capital markets. As such, Enerplus is dependent on continued access to the capital markets to maintain and grow value for unitholders.

Enerplus has listings on the Toronto and New York stock exchanges and maintains an active investor relations program designed to facilitate access to equity capital markets.

Enerplus maintains a prudent capital structure by retaining a portion of the cash flow for debt repayment, rationalizing properties that no longer meet portfolio guidelines, managing capital expenditures within rate of return guidelines, and utilizing the equity markets when deemed appropriate.

Interest Rate Exposure

The Fund has exposure to movements in interest rates. Changing interest rates can affect borrowing costs and the mark-to-market price of yield-based investments such as Enerplus.

Enerplus monitors the interest rate forward market and has fixed the interest rate on a portion of its debt through interest rate swaps for terms of up to three years.

Foreign Currency Rate Exposure

Enerplus has exposure to fluctuations in foreign currency as a result of the issuance of the senior unsecured notes denominated in U.S. dollars.

The Fund has hedged its foreign currency exposure on the senior unsecured notes using financial swaps that convert the U.S. denominated debt to Canadian dollar debt with Canadian dollar interest obligations.

The Fund also has indirect exposure to fluctuations in foreign currency as crude oil sales and a portion of natural gas sales are based on U.S. dollar indices. Enerplus' oil and gas revenues benefit from a weak Canadian dollar relative to the U.S. dollar.

Enerplus has not entered into any foreign currency hedges with respect to crude oil and natural gas sales. However, the Fund is monitoring exchange rates, and it may consider locking in the exchange rate on a portion of its U.S. dollar exposure in the future.

Counterparty Risk

Enerplus assumes customer credit risk associated with oil and gas sales, financial hedging transactions, and joint venture participants.

Management has established credit policies and controls designed to mitigate the risk of default or nonpayment with respect to oil and gas sales, financial hedging transactions, and joint venture participants.

Environmental and Safety Risk

Environmental and safety risks influence the workforce, operating costs, and compliance with regulatory standards.

Enerplus has a site inspections program and a corrosion risk management program designed to ensure compliance with environmental laws and regulations.

Enerplus has training and safety programs designed to educate personnel on safety awareness, monitor incidents and prevent accidents.

Regulatory Risk

Government royalties, income tax laws, environmental laws and regulatory requirements can have a significant financial and operational impact on Enerplus. As a mutual fund trust, Enerplus has a unique structure that is vulnerable to changes in legislation or income tax law.

Although the Fund has no control over these regulatory risks, Enerplus continuously monitors changes in these areas by participating in industry conferences and employing qualified individuals to assess the impact of such changes on the Funds' financial and operating results.

Business Prospects

Enerplus Resources Fund offers investors the benefits of owning a large, diversified portfolio of mature producing crude oil and natural gas properties without the exploration risks commonly associated with traditional E&P companies. As such, Enerplus' business prospects will always be closely linked to the opportunities and challenges associated with crude oil and natural gas production. In particular, Enerplus is strongly influenced by the price of crude oil and natural gas, both of which have been extremely volatile in recent years.

In 2002, Enerplus delivered a 26.5% total return to unitholders through unit appreciation and monthly cash distributions. Looking forward to 2003, Enerplus continues to be focused on delivering top quartile returns to investors. The business plan for 2003 features many of the same strategies that have supported our 17-year track record of success:

Portfolio Optimization

- utilize proven technologies and talented expertise to optimize the performance of existing properties through low-risk development;
- focus the efforts of technical teams on properties with the most potential to add value;
- dispose of non-core properties with limited upside, and re-deploy the proceeds towards key strategic focus areas;

Risk Management

- hedge oil and natural gas prices on a portion of future production to provide protection in the event of adverse commodity price movements, realize positive economic returns from acquisitions and development activity, and provide a measure of stability to the Fund's future cash flows;
- exclude exploration and focus on low-risk development;

Growth

- replace production through a disciplined acquisitions strategy;
- acquire oil and gas producing properties with predictable production profiles, long reserve lives, high cash netbacks, and opportunities for low risk development;
- consider diversification beyond conventional oil and gas into other energy-related investments such as oil sands and processing facilities;
- maintain a portfolio of future development opportunities;
- create and maintain a work environment that attracts and retains qualified professionals;

Corporate Governance

- continue to apply high standards of corporate governance and ethics, including compliance with the regulations and guidelines of Canadian and U.S. securities commissions.

Financing

- utilize debt conservatively;
- diversify credit sources and payment terms;
- hedge interest rates associated with a portion of long-term debt;
- withhold 10 – 20% of cash flow from operations to contribute towards annual development expenditures;
- maintain an active investor relations department in an effort to maintain access to Canadian and U.S. equity markets;
- issue equity for acquisitions and growth opportunities in a manner that adds value to existing unitholders.

We are entering 2003 in an environment of strong commodity prices, volatile global politics, uncertain economic climate, and increasing opportunities for acquisitions. Enerplus' strategy is to maintain its discipline and flexibility to take advantage of opportunities within the context of this marketplace.

Forward–Looking Statements

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of Enerplus. Undue reliance should not be placed on these forward-looking statements which are based upon management's assumptions and are subject to known and unknown risks and uncertainties, including the business risks discussed above, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted. Enerplus undertakes no obligation to update publicly or revise any forward-looking statements contained herein and such statements are expressly qualified by the cautionary statement.

Management's Responsibility for Financial Statements

In Management's opinion, the accompanying consolidated financial statements have been prepared within reasonable limits of materiality and within the framework of generally accepted accounting principles. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgement and with all information available up to March 6, 2003. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, Management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with Management's authorization.

The consolidated financial statements have been examined by Deloitte & Touche LLP, independent chartered accountants. The external auditors' responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with Canadian generally accepted accounting principles. The auditors' report outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting of external directors, has reviewed these statements with Management and the auditors and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Fund.

Gordon J. Kerr
President & Chief Executive Officer
Calgary, Alberta
March 6, 2003

Robert J. Waters
Senior Vice President &Chief Financial Officer

Auditors' Report

To the Unitholders of Enerplus Resources Fund:

We have audited the consolidated balance sheet of Enerplus Resources Fund as at December 31, 2002 and 2001 and the consolidated statements of income, accumulated income, accumulated cash distributions and cash flows for the years then ended. These financial statements are the responsibility of the Fund's Management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards required that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Chartered Accountants

Calgary, Alberta
March 6, 2003

Consolidated Balance Sheet

as at December 31 ($ thousands)	2002	2001
Assets		
Current assets		
Cash	$ 718	$ 979
Accounts receivable	92,986	100,089
Other current	1,975	4,869
	95,679	105,937
Property, plant and equipment	3,071,298	2,667,504
Accumulated depletion and depreciation	(697,153)	(489,188)
	2,374,145	2,178,316
Deferred charges *(Note 2)*	1,807	–
	$2,471,631	$2,284,253
Liabilities		
Current liabilities		
Accounts payable	$ 79,189	$ 72,341
Distributions payable to unitholders	24,870	20,860
Payable to related party *(Note 5)*	19,038	7,915
	123,097	101,116
Long-term debt *(Note 2)*	361,729	412,589
Future income taxes *(Note 4)*	340,269	333,560
Accumulated site restoration	59,038	55,403
Deferred credits	4,266	6,591
Payable to related party *(Note 5)*	1,400	1,909
	766,702	810,052
Equity		
Unitholders' capital *(Note 3)*	2,156,999	1,826,507
Accumulated income	440,446	324,570
Accumulated cash distributions	(1,015,613)	(777,992)
	1,581,832	1,373,085
	$2,471,631	$2,284,253

Signed on behalf of the Board:

Douglas R. Martin
Director

Robert L. Normand
Director

Consolidated Statement of Income

for the year ended December 31 ($ thousands except per trust unit amounts)	2002	2001
Revenues		
Oil and gas sales	$621,450	$639,379
Crown royalties	(99,503)	(101,114)
Freehold and other royalties	(32,334)	(31,546)
	489,613	506,719
Interest and other income	559	858
	490,172	507,577
Expenses		
Operating	134,387	120,082
General and administrative	16,039	12,971
Management fees *(Note 5)*	21,576	9,323
Interest on long-term debt	18,287	17,605
Depletion, depreciation and amortization	213,908	194,080
	404,197	354,061
Income before taxes	85,975	153,516
Capital taxes	5,483	4,722
Future income tax *(Note 4)*	(35,384)	(31,475)
	(29,901)	(26,753)
Net Income	$115,876	$180,269
Net income per trust unit		
Basic	$ 1.61	$ 3.28
Diluted	$ 1.61	$ 3.28
Weighted average number of trust units outstanding (thousands)		
Basic	71,946	54,907
Diluted	72,084	54,956

Consolidated Statement of Accumulated Income

for the year ended December 31 ($ thousands)	2002	2001
Accumulated income, beginning of year	$324,570	$ 144,301
Net income	115,876	180,269
Accumulated income, end of year	$440,446	$ 324,570

Consolidated Statement of Cash Flows

for the year ended December 31 ($ thousands)	2002	2001
Operating Activities		
Net income	$ 115,876	$ 180,269
Depletion, depreciation and amortization	213,908	194,080
Future income taxes (recovery)	(35,384)	(31,475)
Site restoration and abandonment costs incurred	(4,548)	(2,628)
Funds flow from operations	289,852	340,246
Decrease (increase) in non-cash operating working capital	15,162	(52,928)
	305,014	287,318
Financing Activities		
Issue of trust units, net of issue costs *(Note 3)*	329,752	151,411
Cash distributions to unitholders	(233,611)	(328,899)
Increase (decrease) in bank credit facilities	(319,188)	58,021
Issuance of senior unsecured notes	268,328	–
Payment to related party	(509)	(127)
Deferred charges *(Note 2)*	(1,892)	–
	42,880	(119,594)
Investing Activities		
Capital expenditures	(146,116)	(143,280)
Property acquisitions	(60,581)	(77,432)
Property dispositions	3,058	68,496
Corporate acquisitions *(Note 6)*	(161,403)	(14,522)
Change in non-cash investing working capital	16,887	(853)
	(348,155)	(167,591)
Change in cash	(261)	133
Cash, beginning of year	979	846
Cash, end of year	$ 718	$ 979
Supplementary Cash Flow Information		
Cash income taxes paid	$ –	$ –
Cash interest paid	$ 17,740	$ 17,162

Consolidated Statement of Accumulated Cash Distributions

for the year ended December 31 ($ thousands)	2002	2001
Accumulated cash distributions, beginning of year	$ 777,992	$ 447,158
Cash distributions	237,621	330,834
Accumulated cash distributions, end of year	$1,015,613	$ 777,992

(Tabular amounts in thousands of Canadian dollars and thousands of units except per unit amounts)

1. Summary of Significant Accounting Policies

The Management of Enerplus Resources Fund ("Enerplus" or the "Fund") prepares the financial statements in accordance with Canadian generally accepted accounting principles ("GAAP"). A reconciliation between Canadian GAAP and United States GAAP is disclosed in Note 10. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Organization and Basis of Accounting

The Fund is an open-end investment trust created under the laws of the Province of Alberta operating pursuant to the Amended and Restated Trust Indenture between EnerMark Inc., its wholly-owned subsidiary, Enerplus Resources Corporation ("ERC") and CIBC Mellon Trust Company as Trustee. The beneficiaries of the Fund (the "unitholders") are holders of trust units (the "trust units") issued by the Fund. The Fund is a limited-purpose trust whose purpose is to invest in securities of its wholly-owned subsidiary EnerMark Inc., invest in royalties granted by EnerMark Inc. and ERC, administer the assets and liabilities of the Fund and make distributions to the unitholders.

The Fund's financial statements include the accounts of the Fund, EnerMark Inc. and its subsidiaries on a consolidated basis. All inter-entity transactions have been eliminated.

(b) Property, Plant and Equipment

The Fund follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements which extend the recoverable reserves of the property, plant and equipment are capitalized. Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would significantly alter the rate of depletion.

(c) Ceiling Test

The Fund places a limit on the aggregate carrying value of property, plant and equipment which may be amortized against revenues of future periods (the "ceiling test"). The ceiling test is a cost recovery test whereby the capitalized costs less accumulated depletion and depreciation, accumulated site restoration and future income taxes are limited to an amount equal to estimated undiscounted future net revenues from proven reserves, plus the unimpaired costs of non-producing properties, less estimated future general and administrative expenses, site restoration costs, management fees, financing costs and income taxes. Costs and prices at the balance sheet date are used in determining ceiling test amounts. Any costs carried on the balance sheet in excess of the ceiling test limitation are charged to income.

(d) Depletion and Depreciation

The provision for depletion and depreciation of oil and natural gas assets is calculated using the unit-of-production method based on the Fund's share of estimated proven reserves before royalties. Reserves and production are converted to equivalent units on the basis of 6Mcf = 1bbl reflecting the approximate relative energy content.

(e) Site Restoration and Abandonment

The provision for estimated site restoration costs is determined using the unit-of-production method and is included in depletion, depreciation and amortization expense. Actual site restoration costs are charged against the accumulated liability.

(f) Income Taxes

The Fund is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Fund distributes all of its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Fund, no provision for income tax has been made in the Fund, except for its subsidiaries as noted below.

The Fund follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Fund's corporate subsidiaries and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(g) Financial Instruments

The Fund is exposed to market risks resulting from fluctuations in commodity prices, and interest rates in the normal course of operations. The Fund uses various types of financial instruments to manage these market risks. Proceeds and costs realized from holding the crude oil and natural gas contracts are recognized in oil and gas revenues at the time each transaction under a contract is settled. The costs or proceeds realized from holding the interest rate swaps are recognized in interest expense at the time each transaction is settled.

(h) Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at the balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

(i) Accounting for Stock Based Compensation

Effective for the fiscal years beginning on or after January 1, 2002, the Fund adopted the recommendations of the CICA on accounting for stock based compensation which apply to new rights granted on or after that date. The Fund has elected to continue to measure compensation cost based on the intrinsic value of the award at the date of the grant and recognize that cost over the vesting period. The cash received upon exercise of the rights is credited to unitholders' capital.

2. Long-Term Debt

($ thousands)	**2002**	2001
Bank credit facilities (a)	**$ 93,401**	$ 412,589
Senior unsecured notes (b)	**268,328**	-
Total long-term debt	**$ 361,729**	$ 412,589

(a) Bank Credit Facilities

On March 1, 2002, Enerplus renegotiated its bank facilities into a single unsecured syndicated facility (the "Facility") in the amount of $620,000,000. The Facility consisted of a $590,000,000 revolving committed line with an incremental two-year term, and a $30,000,000 demand operating line. The Facility amounts were adjusted upon the issuance of the Senior Unsecured Notes on June 19, 2002, as described below, to a $322,000,000 revolving committed line and a $29,672,000 demand operating line. On November 7, 2002, the Fund's borrowing base was increased by $80,000,000 to $700,000,000 and accordingly the revolving committed line was increased to $402,000,000 along with the total Facility, which at December 31, 2002 was $431,672,000. Various borrowing options are available under the Facility including prime rate based advances and banker's acceptance loans.

In the event that the revolving bank line is not extended at the end of the 364 day revolving period, no payments are required to be made to non-extending lenders during the first year of the term period. However, Enerplus will be required to maintain certain minimum balances on deposit with the syndicate agent.

Since a demand for payment with respect to the operating facility would be financed by the revolving facility, no portion of the operating facility has been considered as current.

(b) Senior Unsecured Notes

On June 19, 2002 Enerplus replaced a portion of its bank debt with senior unsecured notes ("the Notes") in the amount of US$175,000,000. They have a final maturity of June 19, 2014 and bear interest at 6.62% per annum, with interest paid semi-annually on June 19 and December 19 of each year. The Notes Purchase Agreement requires the Fund to make five annual amortizing principal repayments of 20% of the initial principal amount, commencing on June 19, 2010.

Concurrent with the issuance of the Notes, the Fund entered into a cross currency swap, with a syndicate of major financial institutions. Under the terms of the swap, the amount of the Notes was fixed for purposes of interest and principal repayments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian banker's acceptances, plus 1.18%. Costs incurred in connection with issuing the Notes, in the amount of $1,892,000 are classified as deferred charges on the balance sheet and are being amortized over the term of the Notes. As at December 31, 2002, the amount remaining to be amortized associated with these costs was $1,807,000.

The Bank Credit Facilities and the Senior Unsecured Notes (the "Combined Facilities") are the legal obligation of EnerMark Inc. and are guaranteed by ERC. Although payments to unitholders are subordinated to the Combined Facilities, unitholders have no direct liability should cash flow be insufficient to repay the Combined Facilities. However, payments with respect to the Combined Facilities have priority over claims of and future distributions to the unitholders.

3. Fund Capital

(a) Unitholders' Capital

Trust Units (thousands)

Authorized: *Unlimited number of Trust Units*	2002		2001	
Issued:	Units	Amount	Units	Amount
Balance, beginning of year	69,532	$1,826,507	40,925	$1,050,986
Issued for cash:				
Pursuant to public offerings	12,709	314,624	4,313	101,039
Pursuant to option and rights plans	140	2,844	135	2,530
Pursuant to the exercise of warrants	–	–	1,197	33,319
Expiry of warrants	–	–	–	2,846
Issued pursuant to the deemed acquisition of Enerplus *(Note 6)*	–	–	20,863	582,364
Issued pursuant to the management agreement	–	–	173	5,000
Distribution Reinvestment and Unit Purchase Plan	486	12,284	659	16,577
Issued for acquisition of corporate and property interests	31	740	1,267	31,846
Balance, end of year	82,898	$2,156,999	69,532	$1,826,507

During the fourth quarter 2002, the Fund completed an equity offering of 7,959,300 trust units at a price of $26.00 per trust unit for gross proceeds of $206,942,000 ($193,738,000 net of issuance costs).

On September 12, 2002, Enerplus completed an equity offering of 4,750,000 trust units at a price of $26.85 per trust unit for gross proceeds of $127,538,000 ($120,886,000 net of issuance costs).

On November 15, 2001, the Fund issued 4,312,500 trust units at a price of $24.75 per trust unit, to raise gross proceeds of $106,734,000 ($101,039,000 net of issuance costs).

At January 1, 2001, Enerplus had 3,045,000 warrants outstanding with an additional 390,000 issued during the year. During 2001, 1,197,000 warrants were exercised and the remaining 2,238,000 warrants expired.

In accordance with the merger of EnerMark Income Fund ("EnerMark") and Enerplus, (the "Merger"), EnerMark was deemed to have acquired the net assets of Enerplus in exchange for the 20,863,000 trust units of the Fund which were outstanding at June 21, 2001, the date of the acquisition. The deemed trust unit gross consideration was recorded in the amount of $582,817,000 ($582,364,000 net of issuance costs).

Under the terms of the agreement for the provision of management, advisory and administrative services with a related party (Note 5), the Fund issued 172,500 trust units at a recorded value of $5,000,000.

The acquisition of the remaining 11.35% non-controlling interest of Cabre Exploration Ltd. ("Cabre") was completed on January 8, 2001 and resulted in the issuance of 1,267,000 additional trust units, at $25.20 per trust unit for gross consideration of $31,924,000 ($31,846,000 net of issuance costs) and 390,000 additional warrants at $1.27 per warrant for an ascribed value of $496,000.

Enerplus has entered into joint venture agreements (the "Arrangements") with independent corporations (the "Corporations") whose sole purpose is to hold oil and natural gas interests earned under each Arrangement. The terms of the Arrangements require the Corporations to commit funds to be spent in joint ventures with Enerplus. In addition, each Corporation has been granted the option to put its common shares to Enerplus at their fair value as determined by an independent evaluator on specified dates (the "Specified Dates"). Enerplus may elect to pay for the shares by way of cash or through the issuance of trust units of the Fund. If trust units are issued they are to be valued at 95% of their average closing price, for the 60 day period preceding the specified dates. On May 22, 2002, the Corporations involved in the 1999 Arrangement, exercised the option to put their common shares to Enerplus. Enerplus acquired the shares of the Corporation by issuing 31,000 trust units with a value of $740,000. The 2000 Arrangement has an approximate funding commitment of $5,400,000 and a Specified Date of February 1, 2003. The 2001 Arrangement has an approximate funding commitment of $2,700,000 and a Specified Date of March 1, 2004.

Pursuant to the monthly Distribution Reinvestment and Unit Purchase Plan ("DRIP") which applies only to Canadian unitholders, unitholders are entitled to reinvest cash distributions in additional trust units of the Fund. Trust units are issued at a discount of 5% below the weighted average market price on the Toronto Stock Exchange for the twenty trading days preceding a distribution payment date and without service charges or brokerage fees. Unitholders are also entitled to make optional cash payments to acquire additional trust units. Trust units issued pursuant to optional cash payments are issued on the same basis as reinvested cash distributions except no discount applies. During 2002, $12,284,000 was raised pursuant to the DRIP (2001 - $16,577,000).

Trust units are redeemable at any time, on demand by unitholders, at 85% of the market price in effect from time to time. Redemptions cannot exceed $500,000 during any calendar month.

(b) Trust Unit Option Plan

As at December 31, 2002, 123,000 options issued pursuant to the Trust Unit Option Plan were outstanding, representing 0.1% of the total trust units outstanding. Activity for the options issued pursuant to The Trust Unit Option Plan is summarized as follows:

	2002		2001	
(thousands)	Number Of Options	Weighted Average Exercise Price	Number Of Options	Weighted Average Exercise Price
Enerplus Unit Options outstanding				
Beginning of year	264	$20.93	363[1]	$21.03
Exercised	(118)	$19.53	(55)	$21.94
Cancelled	(23)	$22.78	(44)	$20.47
Outstanding at end of year	123	$21.93	264	$20.93
Options exercisable at the end of the year	67	$21.43	99	$19.48

[1] *Number of options represent the balance at June 21, 2001 after the Merger of EnerMark and Enerplus.*

The following table summarizes information with respect to outstanding Unit Options as at December 31, 2002:

(thousands)	**Options Outstanding at December 31, 2002**	**Exercise Prices**	Expiry Date December 31	Options Exercisable December 31, 2002
	17	$17.10	2003	17
	106	$22.90	2004	50
	123	$21.93		67

No new options have been granted under the Trust Unit Option Plan as this plan has been superseded by the Trust Unit Rights Incentive Plan as discussed below.

(c) Trust Unit Rights Incentive Plan

As at December 31, 2002, a total of 2,028,000 rights, representing 2.0% of the total trust units were outstanding pursuant to the Trust Unit Rights Incentive Plan ("Rights Plan") of which 571,000 rights were exercisable. Under the Rights Plan, distributions per trust unit to Enerplus unitholders in a calendar quarter which represent a return of more than 2.5% of the net property, plant and equipment of Enerplus at the end of such calendar quarter result in a reduction in the exercise price of the rights. As at December 31, 2002, the exercise price has been calculated to be reduced by $0.53 per trust unit of which a $0.14 reduction is effective January 2003 and a $0.20 reduction is effective April 2003.

The exercise price of the rights granted under the Fund's Rights Plan may be reduced in the future. The amount of the reduction cannot be reasonably determined as it is dependent on a number of factors including but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of the amounts to be withheld from future distributions to fund capital expenditures and the purchase and sale of property, plant and equipment. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

Compensation costs for pro forma disclosure purposes have been determined based on the excess of the trust unit price over the exercise price of the rights at the date of the financial statements. For the year ended December 31, 2002, net income would be reduced by $181,000 for the estimated compensation cost associated with the rights granted under the Rights Plan on or after January 1, 2002 with a negligible impact on net income per trust unit.

Activity for the rights issued pursuant to the Rights Plan is as follows:

	2002		2001	
(thousands)	Number of Rights	Weighted Average Exercise Price[(1)]	Number of Rights	Weighted Average Exercise Price
Trust Unit Rights outstanding				
Beginning of year	1,318	$ 24.50	–	–
Granted	873	26.18	1,360	$ 24.50
Exercised	(22)	24.31	–	–
Cancelled	(141)	24.44	(42)	24.50
Outstanding at end of year	2,028	25.11	1,318	$ 24.50
Rights exercisable at the end of the year	571	$ 24.31	–	$ –

[(1)] *Exercise price reflects grant prices less reduction in strike price discussed above.*

The following table summarizes information with respect to outstanding Unit Rights as at December 31, 2002:

(thousands)	Rights Outstanding at December 31, 2002	Exercise Prices	Expiry Date December 31	Rights Exercisable December 31, 2002
	1,159	$ 24.31	2007	571
	24	25.38	2008	–
	53	26.33	2008	–
	64	27.33	2008	–
	728	26.09	2008	–
	2,028	$ 25.11		571

4. Income Taxes

(a) Enerplus Resources Fund

The Fund is an inter vivos trust for income tax purposes. As such, the Fund is taxable on any income which is not allocated to the unitholders. The Fund intends to allocate all income to unitholders. Should the Fund incur any income taxes, the cash flow available for distribution will be reduced accordingly.

For 2002, the Fund had taxable income of $157,100,000 (2001 - $181,300,000) or $2.15 per trust unit (2001 - $4.71 per trust unit) which was allocated to unitholders. Taxable income of the Fund is comprised of income on securities issued by EnerMark and royalty income, less deductions for Canadian oil and gas property expense ("COGPE"), which is claimed at a rate of 10% on a declining balance basis and the allowable portion of the cost of issuing new trust units during the period. Any losses which occur in the Fund must be retained in the Fund and may be carried forward and deducted from taxable income for a period of seven years. As at December 31, 2002, the Fund had no losses available for carry forward.

The amounts of COGPE and issue costs remaining in the Fund at December 31, 2002 are $355,456,000 and $22,608,000 respectively (2001 - $381,563,000 and $10,063,000).

(b) Corporate Subsidiaries

The temporary differences, tax effected at the enacted rate, comprising the future income tax liability are as follows:

($ thousands)	2002	2001
Excess of net book value of property, plant and equipment over the underlying tax bases	$ 358,058	$ 350,754
Future site restoration deductions	(18,584)	(17,643)
Other	795	449
Future income tax liability	$ 340,269	$ 333,560

The provisions for income taxes vary from the amounts that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

($ thousands)	2002	2001
Net income before taxes	$ 85,975	$ 153,516
Computed income tax expense at the enacted rate of 42.12% (42.62% for 2001)	$ 36,213	$ 65,429
Increase (decrease) resulting from:		
Effect of change in tax rate	(1,668)	(7,062)
Net income attributed to the Fund	(65,803)	(95,671)
Non-deductible crown royalties and other payments	30,962	43,309
Federal resource allowance	(24,135)	(43,658)
ARTC	(311)	(214)
Adjustments related to prior acquisitions	(10,642)	6,392
Future income taxes (recovery)	$ (35,384)	$ (31,475)

5. Related Party Transactions

Management, advisory and administration services are supplied to the Fund on a fee and cost reimbursement basis, pursuant to an agreement with Enerplus Global Energy Management Company ("EGEM"). As at December 31, 2002, $18,529,000 (2001 - $7,406,000) was payable to EGEM, pursuant to this agreement.

Management fees of $21,576,000 are reported on the Consolidated Statement of Income for the year ended December 31, 2002 (2001 - $9,323,000). This amount is comprised of a base management fee earned equal to $9,208,000 (2001 - $9,323,000) and a performance fee of $12,368,000 (2001 - nil). Performance fees are based on both the total return of the Fund and its relative performance as compared to other senior conventional oil and gas trusts. For the year ended December 31, 2002, performance fees were calculated at 3.5% of net operating income. There was no performance fee recorded for 2001 pursuant to the terms of the management agreement however, in conjunction with the Merger, EGEM received a minimum fee of 172,500 Enerplus trust units with an assigned value of $5,000,000. The fee was accounted for as a cost of the Merger.

Pursuant to a share purchase agreement related to the Merger, the Fund acquired all of the outstanding common shares of ERC from EGEM resulting in ERC becoming a wholly-owned subsidiary of Enerplus. Consideration for the shares was $2,545,000 and is payable over five years in installments of $509,000 through a reduction in management fees. At December 31, 2002, the amount remaining pursuant to this agreement was $1,909,000 ($1,400,000 long term and $509,000 current).

In addition to the transactions described above, Enerplus has entered into financial instrument contracts at prevailing market rates with an indirect subsidiary of El Paso Corporation, the ultimate parent of EGEM, as described in Note 7.

On March 6, 2003 Enerplus announced plans to internalize its management structure by acquiring the shares of the management company, Enerplus Global Energy Management Company ("EGEM"), from an indirect subsidiary of El Paso Corporation ("El Paso") for consideration of approximately $48,900,000. In addition, El Paso agreed to fix the management fee for the period January 1, 2003 to April 23, 2003 in an amount of $3,200,000. The proposed transaction will eliminate all management fees effective April 23, 2003. The transaction is subject to unitholder approval at the annual general and special meeting to be held on April 23, 2003.

6. Corporate Acqusitions

The fair value of the assets acquired and liabilities assumed for the following acquisitions are summarized as follows:

($ thousands)	2002 Celsius	2001 Cabre [1]	2001 Merger
Property, plant and equipment	**$200,156**	$ 18,803	$ 704,838
Working capital	**3,340**	–	(10,415)
Long-term debt assumed	–	–	(78,624)
Site restoration and abandonment	–	–	(14,530)
Future income taxes	**(42,093)**	(11,396)	(524)
Non-controlling interest	–	25,013	–
Net assets acquired	**$161,403**	$ 32,420	$ 600,745

[1] *Represents the acquisition of the remaining 11.35% non-controlling interest.*

(a) Celsius Energy Resources Ltd.

On October 21, 2002, the Fund acquired all the outstanding common shares and retired the debt of Celsius Energy Resources Ltd. ("Celsius"), a private Alberta corporation, for consideration of $161,403,000 which comprised of $160,950,000 in cash and related costs of $453,000. Available lines of credit financed the acquisition which is being accounted for using the purchase method of accounting for business combinations. Results from operations subsequent to October 21, 2002 are included in the Fund's financial statements.

Celsius was amalgamated with EnerMark Inc. effective October 22, 2002 and the amalgamated entity was continued under the name of EnerMark Inc.

(b) Cabre Exploration Ltd.

On January 8, 2001, pursuant to an offer to purchase, initially expiring December 21, 2000 and subsequently extended to January 8, 2001, Enerplus acquired all of the outstanding common shares of Cabre, a public Alberta corporation, of which Enerplus held an 88.65% controlling interest as at December 31, 2000.

On January 17, 2001, Cabre was formally amalgamated with EnerMark Inc. Total consideration for the remaining 11.35% interest was $32,420,000 which consisted of 1,267,000 trust units with a recorded value of $31,924,000 and 390,000 warrants with a recorded value of $496,000.

(c) Enerplus Resources Fund

The Merger of EnerMark and Enerplus which occurred on June 21, 2001 was accounted for using the reverse take-over form of the purchase method of accounting for business combinations as the unitholders of EnerMark became the controlling unitholders of the Fund after the Merger. EnerMark is deemed to have acquired all of the outstanding trust units of Enerplus on June 21, 2001 for fair market value consideration totaling $600,745,000. The 20,863,000 trust units of Enerplus which were outstanding prior to the Merger were recorded as deemed consideration at a value of $582,817,000 representing an exchange value of $27.94 per trust unit. In addition, costs and other charges of $17,928,000 related to the acquisition were recorded.

All disclosures of trust units, warrants and options and per unit data up to the June 21, 2001 Merger date have been restated using the Merger exchange ratio of 0.173 Enerplus unit for each EnerMark unit.

7. Financial Instruments

The Fund's financial instruments that are included in the balance sheet are comprised of current assets, current liabilities, bank credit facilities, and the senior unsecured notes.

The fair values of the current assets and liabilities approximate their carrying amounts due to the short-term maturity of these instruments. The carrying value of the bank credit facilities approximate their fair value as the borrowings have been made through short term banker's acceptances. The fair value of the senior unsecured notes is approximately $305,456,000 which represents the discounted net present value of the future U.S. dollar interest and principal payments based on current interest and foreign exchange rates.

The Fund is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. The Fund uses various types of financial instruments to manage these market risks. The fair values of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding as at December 31, 2002 with reference to forward prices and mark-to-market valuations provided by independent sources. The Fund may be exposed to losses in the event of default by the counterparties to these instruments. This credit risk is controlled by the Fund through the selection of financially sound counterparties.

Interest Rate and Cross Currency Swaps

In addition to the cross currency swap described in Note 2, the Fund has entered into interest rate swaps on $75,000,000 of bank debt at an average fixed interest rate of 4.40% before banking fees that are expected to range between 0.85% and 1.05%. These interest rate swaps are outstanding for three year terms and mature between January 18th and June 4th 2005.

The mark-to-market value of the $75,000,000 interest rate swaps as at December 31, 2002 represents an unrealized loss of $2,000,000. The mark-to-market value of the cross currency swap related to the Senior Unsecured Notes as at December 31, 2002 represents an unrealized gain of $37,100,000.

Crude Oil Instruments

Enerplus has entered into the following financial option contracts that are designed to reduce a downward impact of crude oil prices. The mark-to-market value of the financial crude oil contracts outstanding as at December 31, 2002 reflects an unrealized cost of $8,514,000.

The following table summerizes the Fund's crude oil risk management positions at December 31, 2002:

		WTI US$/bbl		
	Daily Volumes bbls/day	Sold Call	Purchased Put	Sold Put
Term				
Jul. 1, 2003 – Sep. 30, 2003				
3-Way option [(1)]	1,000	$ 32.00	$ 28.00	$23.75
Oct. 1, 2003 – Dec. 31, 2003				
3-Way option [(1)]	1,000	$ 30.00	$ 28.00	$23.95
Jan. 1, 2003 – Sep. 30, 2004				
3-Way option	1,500	$ 29.00	$ 22.00	$ 19.25
Jan. 1, 2003 – Sep. 30, 2004				
3-Way option	1,500	$ 30.00	$ 23.00	$ 20.00
Jan. 1, 2003 – Dec. 31, 2003				
3-Way option	1,500	$ 27.00	$ 19.50	$ 17.00
3-Way option	1,500	$ 28.00	$ 20.15	$ 17.00
3-Way option	1,500	$ 28.51	$ 22.00	$ 19.50
Jan. 1, 2003 – Jun. 30, 2004				
3-Way option	1,500	$ 28.00	$ 22.50	$ 19.60
3-Way option	500	$ 28.00	$ 22.50	$ 19.90
Jan. 1, 2003 – Dec. 31, 2004				
3-Way option	1,500	$ 29.50	$ 22.00	$ 20.00
Jan. 1, 2004 – Dec. 31, 2004				
3-Way option	1,000	$28.10	$23.00	$20.50
3-Way option [(1)]	1,000	$28.50	$25.00	$22.00

[(1)] *Transactions entered into subsequent to December 31, 2002 that are not included in the mark-to-market values.*

Natural Gas Instruments

Enerplus has the following physical and financial contracts in place on its gross natural gas production as described below. The mark-to-market value of the financial natural gas contracts outstanding as at December 31, 2002 reflects an unrealized cost of $34,190,000.

The following table summarizes the Fund's natural gas risk management positions as at December 31, 2002:

	Annualized Daily Volumes MMcf/d	AECO$/Mcf CDN$ Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps	Escalated Price
Term						
Jan. 1, 2003 - Mar. 31, 2003						
3-way option [3]	4.8	$7.39	$5.28	$4.22	–	–
3-way option [4]	4.8	$7.39	$5.28	$4.22	–	–
Jan. 1, 2003 - Mar. 31, 2003						
Call	9.5	$6.33	–	–	–	–
Jan. 1, 2003 - Oct. 31, 2003						
Physical	2.8	–	–	–	$2.64	–
Collar [1]	7.1	$5.27	$3.69	–	–	–
Put [1]	7.1	–	$3.69	–	–	–
Jan. 1, 2003 - Dec. 31, 2003						
Physical	2.0	–	–	–	–	$2.23
3-way option	9.5	$7.91	$4.27	$3.17	–	–
Swap	5.7	–	–	–	$5.80	–
Jan. 1, 2003 - Jun. 30, 2004						
3-way option	9.5	$7.39	$4.75	$3.17	–	–
Jan. 1, 2003 - Sep. 30, 2004						
3-way option	9.5	$6.67	$4.75	$3.17	–	–
3-way option	9.5	$7.39	$4.75	$3.69	–	–
Jan. 1, 2003 - Oct. 31, 2006						
Swap	9.5	–	–	–	$5.47	–
Swap	4.8	–	–	–	$5.25	–
Swap	4.8	–	–	–	$5.24	–
Swap	4.8	–	–	–	$5.28	–
Apr. 1, 2003 - Oct. 31, 2003						
Collar	4.8	$6.33	$4.75	–	–	–
Collar	4.8	$6.18	$4.75	–	–	–
Apr. 1, 2003 - Dec. 31, 2004						
3-way option [2]	9.5	$7.91	$5.80	$4.22	–	–
Jan. 1, 2003 - Oct. 31, 2004						
Swap	3.8	–	–	–	$2.90	–
Jan. 1, 2004 - Dec. 31, 2004						
Swap	2.8	–	–	–	$5.51	–
2004 - 2010						
Physical	2.0	–	–	–	–	$2.52

[1] *The counterparty to these natural gas collars and puts, is a subsidiary of El Paso Corporation which is the ultimate parent of EGEM (refer to Note 5). The option premiums for these instruments are $1,694,000 and are being amortized over their remaining terms.*

[2] *Transactions entered into subsequent to December 31, 2002 that are not included in the mark-to-market values.*

[3] *Enerplus sells physical gas at the Month Index less $0.05/Mcf.*

[4] *Enerplus sells physical gas at the Month Index less $0.11/Mcf.*

8. Commitments and Contingences

Pipeline Transportation

Enerplus has contracted to transport natural gas with various pipelines totaling 15 MMcf per day until 2008 and a further 5 MMcf per day until 2015. These transportation contracts apply to approximately 10% of the Fund's natural gas production.

Oil Sands Lease #24

During 2002, the Fund acquired a 16% working interest in the Oil Sands Lease #24 (Josyln Creek Lease). The acquisition included the assumption of approximately $4,179,000 in contingent project debt that was comprised of $3,360,000 of principal and approximately $819,000 in accrued interest at December 31, 2002. Interest is accrued at the Bank of Canada prime business rate and is not compounded. The debt is contingent on both production and pricing hurdles with respect to development on the lease. As it is too early in the development of this project to determine if these hurdles will be satisfied, the contingent debt has not been accrued in the consolidated financial statements.

9. Event Subsequent to December 31, 2002

Subsequent to December 31, 2002, the Fund acquired all of the issued and outstanding shares of PCC Energy Inc. and PCC Energy Corp. (collectively "PCC") for total cash consideration of $167,600,000. The acquisition will be accounted for using the purchase method of accounting for business combinations with the results of operations included in the consolidated financial statements of the Fund from the closing date of March 5, 2003.

10. Differences Between Canadian and United States Generally Accepted Accounting Principles

The Fund's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles, as they pertain to the Fund's consolidated statements, differ from United States GAAP ("U.S. GAAP") as follows:

(a) Under U.S. GAAP, for Securities and Exchange Commission registrants following full cost accounting, the carrying value of petroleum and natural gas properties and related facilities, net of deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at ten percent (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. Under Canadian GAAP, the ceiling test is calculated without application of a discount factor, but includes general and administrative expenses, management fees and interest expense.

Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion, depreciation, and amortization will differ in subsequent years. As at December 31, 2002, the application of the ceiling test under U.S. GAAP did not result in a write-down of capitalized costs. At December 31, 2001, the application of the ceiling test under U.S. GAAP resulted in a write down of $744,300,000 ($458,400,000 after tax) of capitalized costs. Under Canadian GAAP, the application of the ceiling test did not result in a write down in either year.

(b) The Financial Accounting Standards Board's ("FASB") Statement of Financial Standards ("SFAS") No. 123, "Accounting for Stock-based Compensation", establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by SFAS 123, Enerplus has elected to continue to measure compensation expense based on the intrinsic value of the award when accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board Opinion 25. Since all Unit Options and Trust Unit Rights were granted with an exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income. Had compensation cost for Enerplus

Unit Options granted prior to January 1, 2002 been determined based on the fair market value at the grant dates of the awards consistent with the methodology prescribed by SFAS 123, Enerplus' net income (loss) and net income (loss) per unit for years ended December 31, 2002 and 2001 would have been the pro forma amounts indicated below:

($ thousands)	2002	2001
Net income (loss):		
As reported under U.S. GAAP	$ 149,384	$ (261,288)
Pro forma	148,859	(262,191)
Net income (loss) Per Trust Unit		
Basic		
As reported under U.S. GAAP	$ 2.08	$ (4.76)
Pro forma	$ 2.07	$ (4.78)
Diluted		
As reported under U.S. GAAP	$ 2.07	$ (4.76)
Pro forma	$ 2.07	$ (4.78)

As the exercise price of the trust unit rights is subject to downward revisions from time to time, the Rights Plan is a variable compensation plan under U.S. GAAP. Accordingly, compensation expense is determined on the rights as the excess of the market price over the exercise price of the rights at the end of each reporting period and is deferred and recognized in income over the vesting period of the rights. During 2002, a $0.19 per right downward reduction in the exercise price on 1,400,000 rights had occurred. Accordingly, a charge to net income was recognized for the year ended December 31, 2002 of $3,406,000. For the year ended December 31, 2001 no downward revision in exercise price had occurred and no compensation expense was recognized for the rights.

(c) Under U.S. GAAP the measurement date for acquisitions is the date the acquisition is announced. Previously to June 1, 2001 under Canadian GAAP the measurement date for the acquisition was the closing date. Therefore, under U.S. GAAP, unitholders' capital and property, plant and equipment have been increased by $37,300,000 in 2001 for differences in the value of trust units issued to effect the Merger.

(d) Effective January 1, 2001, for U.S. reporting purposes, the Fund adopted Statement of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities". SFAS 133 establishes accounting and reporting standards requiring that all derivative instruments (including derivative instruments embedded in other contracts), as defined, be recorded in the balance sheet as either an asset or a liability measured at fair value and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met.

With respect to its crude oil and natural gas contracts that do not qualify for hedge accounting treatment under SFAS 133, the Fund has recognized in earnings a loss of $25,312,000 ($14,529,000 net of tax) in 2002 compared to a loss of $437,000 ($251,000 net of tax) in 2001.

(e) U.S. GAAP requires the reporting of comprehensive income in addition to net earnings. The Fund's comprehensive income for the year ended December 31, 2002 includes a net unrealized gain of $10,415,000 on instruments qualifying for hedge accounting under SFAS 133. The net unrealized gain is comprised of $2,000,000 ($1,148,000 net of tax) unrealized hedging loss on the $75,000,000 interest rate swap, an unrealized hedging gain of $37,100,000 ($21,295,000 net of tax) relating to the combined cross currency and interest rate swap on the senior unsecured notes and an unrealized loss of $16,955,000 ($9,732,000 net of tax) relating to the change in fair value of certain of the Fund's natural gas contracts. For the year ended December 31, 2001, the Fund's net income was equal to its comprehensive income.

(f) Recent Developments in U.S. Accounting Standards

In June 2001, the FASB issued SFAS 143, "Accounting for Asset Retirement Obligations." SFAS 143 requires liability recognition for retirement obligations associated with tangible long-lived assets. The obligations included within the scope of SFAS 143 are those for which the Fund faces a legal obligation for settlement. The initial measurement of the asset retirement obligation is to be capitalized as part of the cost of the related long-lived asset and amortized to expense over the useful life of the asset. SFAS 143 is effective for all fiscal years beginning on or after June 15, 2002. The total impact on the Fund's financial statements has not yet been determined.

The application of U.S. GAAP would have the following effects on net income as reported:

($ thousands)	2002	2001
Net income as reported in the Consolidated		
Statement of Income - Canadian GAAP	$ 115,876	$ 180,269
Adjustments, net of tax		
Write-down of property, plant and equipment	–	(458,474)
Depletion, depreciation and amortization	51,443	17,168
Compensation expense	(3,406)	–
Unrealized (loss) on financial derivatives	(14,529)	(251)
Net income (loss) - U.S. GAAP	$ 149,384	$ (261,288)
Net unrealized gain on hedging instruments, net of tax	10,415	–
Comprehensive income (loss)	$ 159,799	$ (261,288)
Net income (loss) per trust unit		
Basic	$ 2.08	$ (4.76)
Diluted	$ 2.07	$ (4.76)
Weighted average number of trust units outstanding		
Basic	71,946	54,907
Diluted	72,084	54,956
Accumulated other comprehensive income	$ –	$ –
Balance, beginning of year	–	–
Net unrealized gain on hedging instruments, net of tax	10,415	–
Balance, end of year	$ 10,415	$ –

The application of U.S. GAAP would have the following effects on the balance sheet as reported:

($ thousands)	Canadian GAAP	Increase (decrease)	U.S. GAAP
December 31, 2002			
Financial derivative assets	–	$ 37,100	$ 37,100
Property, plant and equipment, net	$ 2,374,145	(935,099)	1,439,046
Financial derivative liabilities	–	44,704	44,704
Future income taxes	340,269	(377,541)	(37,272)
Unitholders' capital	2,156,999	29,626	2,186,625
Contributed surplus	–	3,406	3,406
Accumulated income	440,446	(608,610)	(168,164)
Accumulated other comprehensive income	–	10,415	10,415
December 31, 2001			
Financial derivative assets	–	274	274
Property, plant and equipment, net	2,178,316	(1,018,610)	1,159,706
Financial derivative liabilities	–	711	711
Future income taxes	333,560	(406,556)	(72,996)
Unitholders' capital	1,826,507	29,626	1,856,133
Accumulated income	324,570	(642,117)	(317,547)

SFAS No. 69 Supplemental Reserve Information (unaudited)

The following disclosures have been prepared in accordance with SFAS No. 69–"Disclosures about Oil and Gas Producing Activities":

Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and the Fund's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Fund's share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2002 no major discovery or other favorable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

Results of Operations for Producing Activities

The following table sets forth revenue and direct cost information relating to the Fund's oil and gas producing activities for the years ended December 31.

($ thousands) [1]	2002	2001
Revenue		
Sales [2]	$ 489,613	$ 506,719
Deduct		
Production Costs	134,387	120,082
Depletion, depreciation and amortization and valuation Provision	130,397	910,486
Results of operation from producing activities	$ 224,829	$ (523,849)

[1] *The costs in this schedule exclude corporate overhead, interest expense and other costs which are not directly related to producing activities.*

[2] *Sales are net of royalties and third party obligations.*

Costs incurred in oil and gas producing activities for the years ended December 31 are as follows:

($ thousands)	2002	2001
Acquisition costs of proved properties	$ 218,644	$ 799,636
Development costs	141,752	141,509
	$ 360,396	$ 941,145

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties. Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and gas, along with an allocation of overhead. There were no oil and gas property costs not being amortized in any of the years presented.

Capitalized Costs Relating to Oil and Gas Producing Activities

The capitalized costs and related accumulated depreciation, depletion and amortization, including impairments, relating to the Fund's oil and gas exploration, development and producing activities at December 31 consist of:

($ thousands)	2002	2001
Proved oil and gas properties	$ 3,054,141	$ 2,654,711
Less accumulated depletion, depreciation and amortization	1,621,363	1,500,037
Net capitalized costs	$ 1,432,778	$ 1,154,674

Oil and Gas Reserve Information

All of the Fund's proved oil, natural gas liquids, and natural gas reserves are located in Canada, primarily in the provinces of Alberta, British Columbia, and Saskatchewan. The Fund's proved developed and undeveloped reserves after deductions of royalties are summarized below:

	Crude Oil and NGLs (MMbbls)	Natural Gas (Bcf)
Net Proved Developed and Undeveloped Reserves After Royalties [1]		
End of year 2000 (EnerMark Income Fund)	**57.2**	**496.2**
End of year 2000 (Enerplus Resources Fund)	**44.1**	**246.3**
End of year 2000 (combined)	**101.3**	**742.5**
Revisions of previous estimates	(1.1)	60.8
Purchase of reserves in place		
EnerMark Income Fund	3.3	18.0
Enerplus Resources Fund (prior to June 21)	1.1	0.2
Combined	4.4	18.2
Sales of reserves in place		
EnerMark Income Fund	(3.6)	(12.6)
Enerplus Resources Fund (prior to June 21)	(1.0)	(4.6)
Combined	(4.6)	(17.2)
Discoveries and extensions	–	–
Production (combined)	(8.9)	(59.4)
End of year 2001	**91.1**	**744.9**
Revisions of previous estimates	21.1	76.6
Purchase of reserves in place	7.3	60.2
Sales of reserves in place	(0.5)	(0.1)
Discoveries and extensions	–	–
Production	(8.3)	(58.3)
End of year 2002	**110.7**	**823.3**
Net Proved Developed Reserves After Royalties [1]		
End of year 2000 (EnerMark Income Fund)	50.1	395.5
End of year 2000 (Enerplus Resources Fund)	42.3	185.8
End of year 2001	83.6	605.5
End of year 2002	101.3	663.8

[1] *Net after royalty reserves are the Fund's lessor royalty, overriding royalty, and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.*

Reserves are the estimated quantities of crude oil, natural gas and related substances anticipated from geological and engineering data to be recoverable from known accumulations, from a given date forward, by known technology, under existing operating conditions and prices in effect at year end.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information has been developed utilizing procedures described by SFAS No. 69 and based on crude oil and natural gas reserve and production volumes estimated by the independent engineering consultants of the Fund. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Fund or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Fund's reserves.

The future cash flows presented below are based on sales prices, cost rates, and statutory income tax rates in existence as of the period end date. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2002 was based on a crude oil price of $48.24/bbl and natural gas price of $5.88/Mcf. The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2001 was based on the Fund's crude oil price of $30.35/bbl and natural gas price of $3.75/Mcf.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Fund's crude oil and natural gas reserves at December 31, for the years presented.

($ millions)	2002	2001
Future cash inflows	$ 6,554	$ 2,558
Future production and development costs	(203)	(142)
Future net cash flows	6,351	2,416
Deduction: 10% annual discount factor	(3,318)	(1,154)
Standardized measure of discounted future net cash flows	$ 3,033	$ 1,262

Changes in Standardized Measure of Discounted Future Cash Flow Relating to Proved Oil and Gas Reserves

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31 for the years presented.

($ millions)	2002	2001
Future discounted net cash flows at beginning of year	$ 1,262	$ 2,314
Sales and transfer, net of production costs	(252)	(277)
Net change in sales and transfer prices, net of development and production costs	1,434	(1,860)
Extension, discoveries and improved recovery, net of related costs	–	–
Revisions of quantity estimates	346	91
Accretion of discount	150	125
Sales of reserves in place	(5)	(89)
Purchase of reserves in place	173	1,033
Changes in timing of future cash flows and others	(75)	(75)
Net change income taxes	–	–
End of year	$ 3,033	$ 1,262

(1) *The schedules above are calculated using year-end prices, costs, statutory tax rates and existing proved oil and gas reserves. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.*

5 Year Detailed Statistical Review

The information contained in the table below reflects the reverse takeover of Enerplus by EnerMark on June 21, 2001 as required by Canadian generally accepted accounting principles.

($ thousands, except per Unit amount)	2002	2001	2000	1999	1998
Financial					
Oil and gas sales	$ 621,450	$ 639,379	$ 343,182	$169,541	$134,102
Cash available for distribution	$ 246,787	$ 316,454	$ 168,181	$ 78,189	$ 70,059
Per Unit	$ 3.32	$ 5.67	$ 5.49	$ 3.70	$ 3.70
Net income	$ 115,876	$ 180,269	$ 82,150	$ 25,754	$ 8,881
Per Unit	$ 1.61	$ 3.28	$ 3.06	$ 1.25	$ 0.47
Total net capital expenditures	$ 365,042	$ 874,420	$ 700,714	$ 17,837	$ 56,516
Total assets	$2,471,631	$ 2,284,253	$1,567,952	$576,901	$617,881
Bank debt, net of working capital	$ 389,147	$ 407,768	$ 315,820	$142,066	$188,762
Net debt/funds flow ratio	1.3 x	1.2 x	1.8 x	1.8 x	3.0 x

($ per BOE except percentage data)	2002	2001	2000	1999	1998
Oil and Gas Economics					
Net royalty rate	21%	23%	23%	19%	14%
Weighted average price (net of hedging)	$ 27.11	$ 32.43	$ 30.14	$ 18.32	$ 13.39
Net royalty expense	5.75	6.73	7.10	3.47	1.87
Operating expense	5.86	6.09	4.83	4.02	4.04
Operating netback	15.50	19.61	18.21	10.83	7.48
General and administrative expense	0.70	0.66	0.63	0.62	0.56
Management fee	0.94	0.47	0.40	0.24	0.15
Interest expense, net of interest and other income	0.78	0.85	1.30	0.87	0.16
Capital taxes	0.23	0.24	0.26	0.17	0.20
Restoration and abandonment cash costs	0.20	0.13	0.13	0.12	0.10
Gain on sale of investment	-	-	-	0.06	0.03
Funds flow from operations	$ 12.65	$ 17.26	$ 15.49	$ 8.75	$ 6.28

Combined Operational Statistics

The information contained in the table below reflects the combined results of Enerplus and EnerMark for the years indicated as if the combination of the Funds had been effective January 1, 1997. This information may not be representative of the actual results had the combination occurred on that date. No pro forma adjustments have been made to give effect to the combination of Enerplus and EnerMark for these periods. The information in this table is different from the financial statements and MD&A which account for the combination as a reverse takeover of Enerplus by EnerMark on June 21, 2001 as required by Canadian generally accepted accounting principles.

	2002	2001	2000	1999	1998
Daily Production					
Crude oil per day (bbls)	**23,288**	24,010	18,118	16,938	17,934
NGLs per day (bbls)	**4,410**	4,650	3,395	3,153	3,603
Natural Gas per day (Mcf)	**210,517**	203,727	149,616	119,303	128,282
Total BOE per day	**62,784**	62,615	46,449	39,975	42,917
Proven Reserves					
Crude oil (Mbbls)	**105,247**	94,847	101,439	71,756	77,077
NGLs (Mbbls)	**16,035**	16,114	16,973	11,740	13,188
Natural Gas (MMcf)	**1,001,913**	951,133	954,124	550,275	551,143
Total MBOE	**288,267**	269,483	277,433	175,209	182,122
Probable Reserves					
Crude oil (Mbbls)	**33,450**	37,642	41,350	27,541	24,975
NGLs (Mbbls)	**4,638**	4,674	3,445	3,240	3,916
Natural Gas (MMcf)	**277,578**	260,690	263,636	531,277	471,943
Total MBOE	**84,350**	85,764	88,734	119,327	107,548
Established Reserves (proven and 50% of probable)					
Crude oil (Mbbls)	**121,972**	113,668	122,114	85,671	89,566
NGLs (Mbbls)	**18,354**	18,451	18,696	13,375	15,144
Natural Gas (MMcf)	**1,140,702**	1,081,478	1,085,942	779,631	615,172
Total MBOE	**330,442**	312,365	321,800	228,985	207,239
Established reserve life index (years) BOE Combined [1]	**13.8**	14.0	13.7	13.5	14.2

[1] *The established Reserve Life Index (RLI) is based upon year end established reserves divided by following year production volume estimates.*

Income Tax - Canadian Residents (CDN$/Unit)

The following table outlines the breakdown of cash distributions per Unit paid or payable by Enerplus Resources Fund during the period February 10, 2002 up to and including January 10, 2003 for Canadian income tax purposes.

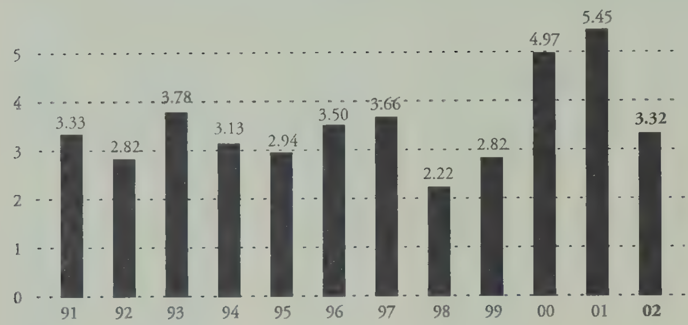
Record Date	Payment Date	Total Distribution Paid	Taxable Income Amount	Taxable Dividend Amount	Return of Capital Amount
February 10	February 20	$0.2500	$0.1600	$0.0053	$0.0847
March 10	March 20	$0.2000	$0.1269	$0.0053	$0.0678
April 10	April 20	$0.2000	$0.1269	$0.0053	$0.0678
May 10	May 20	$0.2800	$0.1798	$0.0053	$0.0949
June 10	June 20	$0.2800	$0.1798	$0.0052	$0.0950
July 10	July 20	$0.2800	$0.1798	$0.0052	$0.0950
August 10	August 20	$0.2800	$0.1799	$0.0052	$0.0949
September 10	September 20	$0.2800	$0.1799	$0.0052	$0.0949
October 10	October 20	$0.3000	$0.1934	$0.0049	$0.1017
November 10	November 20	$0.3000	$0.1934	$0.0049	$0.1017
December 10	December 20	$0.3000	$0.1939	$0.0044	$0.1017
December 31	January 20	$0.3000	$0.1939	$0.0044	$0.1017
Total per Unit		**$3.2500**	**$2.0876**	**$0.0606**	**$1.1018**

Income Tax - United States Residents (US$/Unit)

The following table outlines the breakdown of cash dividends paid per Unit by Enerplus Resources Fund, prior to any amounts deducted for Canadian withholding tax, for Units held through a broker or other intermediary for the period January 20, 2002 to December 20, 2002 for U.S. income tax purposes. All amounts shown are in U.S. dollars as converted on the applicable payment date.

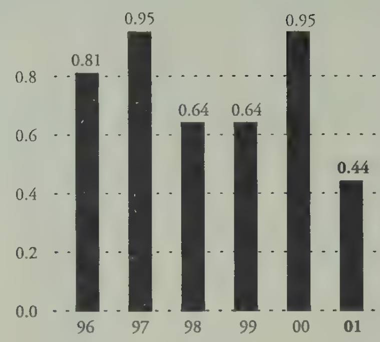
Record Date	Payment Date	Total Distribution Paid in US$	Taxable Ordinary Dividend Amount	Non-Taxable Return of Capital Amount
December 31, 2001	January 20	$0.1865	$0.1350	$0.0515
February 10	February 20	$0.1571	$0.1137	$0.0434
March 10	March 20	$0.1265	$0.0916	$0.0349
April 10	April 20	$0.1271	$0.0920	$0.0351
May 10	May 20	$0.1817	$0.1315	$0.0502
June 10	June 20	$0.1825	$0.1321	$0.0504
July 10	July 20	$0.1798	$0.1302	$0.0497
August 10	August 20	$0.1778	$0.1287	$0.0491
September 10	September 20	$0.1779	$0.1288	$0.0491
October 10	October 20	$0.1910	$0.1383	$0.0527
November 10	November 20	$0.1891	$0.1369	$0.0522
December 10	December 20	$0.1928	$0.1396	$0.0532
Total per Unit		**$2.0699**	**$1.4984**	**$0.5715**

Historical Annual Cash Distributions



Enerplus Cash Distributions

CDN$ per Unit



EnerMark Cash Distributions

CDN$ per Unit

Unit Trading Information

ERF.un trading information on Toronto Stock Exchange as at December 31,

CDN$	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	**2002**
High	18.60	25.20	30.00	33.00	35.25	33.00	25.50	19.20	24.60	32.86	**29.00**
Low	13.56	13.50	22.20	21.60	28.50	20.40	12.00	12.60	15.60	22.00	**22.85**
Close	15.00	23.10	27.00	32.25	32.40	23.40	12.96	16.32	22.90	24.75	**28.05**
Volume 000	1,680	5,079	4,245	9,898	16,160	12,672	8,230	7,322	10,214	29,466	**37,492**

Enerplus Resources Fund began trading on the New York Stock Exchange on November 17, 2000. ERF trading information on the New York Stock Exchange as at December 31,

US$	2000	2001	**2002**
High	15.25	23.50	**19.08**
Low	14.69	13.79	**14.30**
Close	15.25	15.56	**17.75**
Volume	121	19,740	**31,350**

Distribution Reinvestment Unit Purchase Plan

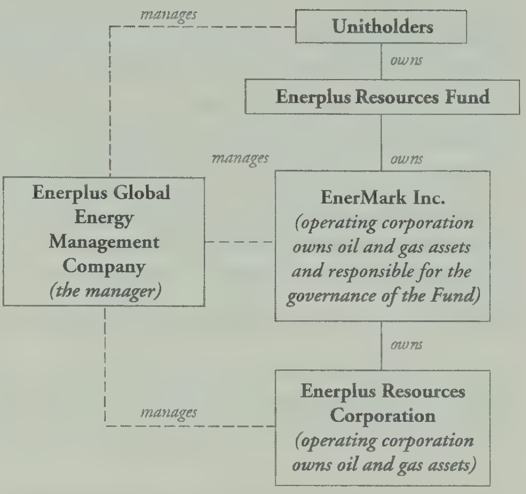
Enerplus Resources Fund has a convenient method for Canadian Residents to reinvest cash distributions or invest additional funds into new Trust Units. Residents of Canada who hold at least one Trust Unit, are eligible to participate in the Plan.

If your Units are held for you by your broker, investment dealer or other financial intermediary, you must direct that company to enrol your Units into the Plan.

To obtain more information and/or enrolment forms, please contact Enerplus' Investor Relations Department at 1-800-319-6462, in Calgary at (403) 298-2200, by fax at (403) 298-2211 or by Email at investorrelations@enerplus.com.

Statement of Corporate Governance Practices

At the present time, the corporate governance structure of Enerplus Resources Fund (the "Fund") is not the same as for a conventional corporation. The way in which the Fund is governed reflects its status as a trust. The Board of Directors (the "Board") of EnerMark Inc. ("EnerMark"), a wholly-owned subsidiary of the Fund, is responsible for the overall governance of the Fund (see diagram below). However, the management of the Fund is provided by Enerplus Global Energy Management Company ("the Manager") pursuant to a Management, Advisory and Administration Agreement between the Fund, its subsidiaries, the Manager and the CIBC Mellon Trust Company (the trustee to the Fund).



The Board of Directors

The Board is currently comprised of eight members, five of whom are unrelated (as defined in the Toronto Stock Exchange Guidelines for Improved Corporate Governance in Canada) and elected by the Fund's unitholders. The remaining three directors are nominated by the Manager pursuant to a Governance Agreement entered into with the Fund, its subsidiaries and trustee of the Fund. At the next scheduled annual general meeting of the unitholders of the Fund, an additional unrelated director has been nominated to expand the membership of the Board to nine and the number of unrelated directors to six.

The Board is charged with the overall stewardship of the Fund as more particularly described in its mandate. To summarize its mandate here, the Board has responsibility for:

- reviewing, adopting and monitoring the Fund's strategic planning process;
- reviewing and approving the Fund's operating budget;
- considering principal risks and reviewing and approving risk management strategies;
- approving corporate policies and other corporate protocols and controls;
- approving goals and objectives for the Fund;
- succession planning, including nominating and monitoring senior management; and
- ensuring the integrity of internal financial controls and reviewing management information systems.

The Board meets a minimum of six times per year and each scheduled board meeting is followed by a meeting of the independent directors without the presence of management. Management is responsible to ensure the Board has timely access to the information it needs to carry out its duties. Directors assist in preparing the agenda for Board and committee meetings, receive a comprehensive package of information in advance of each Board and committee meeting, and attend an annual strategic planning session each fall to review, amend or adopt new corporate objectives.

In 2002, the Board instituted a formal assessment process for itself and its members; this has now become an annual review. The results of this assessment has helped the Board enhance its corporate governance practices. Through the Board, the Fund has made substantial progress in strengthening its governance practices and has responded quickly and effectively to external events which have eroded investor confidence in the North American marketplace.

The Board has approved a Code of Business Conduct and Conflict of Interest (the "Code") which sets standards of ethical behaviour for all directors. Among other things, the Code deals with issues such as conflict of interest, compliance with laws, outside business interests, acceptance of gifts and favours, disclosure of confidential information and securities trading and reporting. Each director must adhere to the standards described in the Code and must review, sign and deliver to the Chairman of the Board a copy of this Code each year. The Code of Business Conduct and Conflict of Interest can be found, in its entirety, on our website at www.enerplus.com. In addition to the Code, the Manager and all its employees (including senior management) also operate pursuant to a code of business conduct entitled "Ethics in Practice" ("Ethics Code"). The Ethics Code is a code of conduct pursuant to which the shareholder of the Manager and the Manager and its employees conduct business. Like the Code, it requires all who are subject to it to operate with integrity and in an ethical manner. To view the Ethics Code in its entirety, it can be found on our website at www.enerplus.com.

The current corporate governance structures, policies and practices of the Board and its committees has enabled the Board to conclude that the Fund is in full compliance with the Guidelines of Corporate Governance established by the Toronto Stock Exchange ("TSX") and which is more particularly outlined in the Fund's Information Circular and Proxy Statement.

The Board of Directors discharges its responsibilities either acting in its entirety, or through one of its three board committees.

Corporate Governance and Human Resources Committee

In January 2003, the Corporate Governance Committee and the Human Resources and Compensation Committee held a joint meeting to review their respective mandates and responsibilities. It became apparent that the committees dealt with many related matters and that efficiencies could be achieved by combining the two committees. As a result of these findings, the Board approved of the combination of the committees on February 5, 2003, to form the Corporate Governance and Human Resources Committee. The Corporate Governance and Human Resources Committee is currently comprised of three unrelated directors. The principle responsibilities of the Committee are twofold in nature.

Corporate Governance

Firstly, the Committee has a primary responsibility to ensure the Fund utilizes best practices in the area of corporate governance. This is accomplished by:

- reviewing the Fund's compliance with legislative, regulatory and stock exchange protocols respecting corporate governance best practices;
- ensuring the size and composition of the Board reflects diversity of experience for effective decision making;
- reviews and amends the mandates of the Board's committees;
- reviewing the credentials of new nominees to the Board and the past performance of incumbent nominees proposed for reelection at the annual general meeting of unitholders of the Fund; and
- overseeing the effectiveness of management and management's interaction with and responsiveness to the concerns and requests of the Board.

The Committee has also championed the development of an orientation program developed for new directors of the Board. Pursuant to this program, the new director is provided with a Corporate Governance Manual and an opportunity to meet with and question the Chairman of the Board and the senior management of the Fund.

Human Resources

Another primary responsibility of the Committee relates to employment, compensation and human resource matters of the Fund. In satisfying this obligation, the Committee:

- assesses the performance of the Chief Executive Officer and senior management generally, with reference to corporate objectives set and approved by the Board at the annual strategic planning session;
- reviews the annual performance assessments submitted by the Chief Executive Officer of senior executives;
- reviews and recommends to the Board executive compensation policies, programs and awards;
- reviews and approves the granting of trust unit rights to directors, officers and employees under the Trust Unit Rights Incentive Program;
- reviews and recommends to the Board awards under the performance incentive plan which are determined with reference to pre-approved corporate objectives;
- reviews compensation at all levels to ensure that the Fund remains competitive and retains talented employees to ensure the continued success of the Fund;
- reviews and ensures that long-term succession plans for senior executive positions are appropriate; and
- reviews the compensation paid to directors to ensure that it is competitive with industry standards.

From time to time, the Committee will engage independent consultants to ensure its compensation practices on all levels are aligned with those of comparable Canadian and U.S. corporations.

Audit and Risk Management Committee

The Audit and Risk Management Committee is currently comprised of three unrelated directors, all of whom are financially literate. The Chairman of the Committee has a Chartered Accountant designation and another member holds a Chartered Financial Analyst designation. The Committee is responsible for the quality of the Fund's financial reporting and operates pursuant to a charter which identifies its objectives and responsibilities.

During the year, the Committee undertook a general review of its duties and responsibilities and specifically focussed on the financial disclosure reports, the adequacy of internal financial controls and related disclosure materials of the Fund in light of the legislative and regulatory changes resulting from the recent passage of the Sarbanes-Oxley Act of 2002 in the United States. Following this intensive review, the current responsibilities and duties of the Committee include:

- reviewing with management and the external auditors the interim and annual financial statements;
- reviewing with the external auditors the use by management of generally accepted accounting principles, their consistent application and their appropriateness;
- assessing the effectiveness and suitability of the processes relating to the evaluation of the Fund's internal financial controls;
- engaging the Fund's external auditors and assessing their performance annually;
- reviewing and approving the annual audit plan and audit fees;
- approving unrelated audit services, where applicable;
- reviewing financial reporting systems;

- reviewing the processes by which management identifies, measures and manages the various financial risks of the business and the proper disclosure respecting same;

- reviewing, together with the full Board, the hedging and derivatives policies of, and transactions entered into by, management of the Fund; and

- ensuring the chief executive officer and the chief financial officer certify the accuracy of the information set forth in the consolidated annual financial statements and related disclosure materials of the Fund.

In the fall of 2002, the Committee endorsed the creation and implementation of a policy to encourage employees and consultants of the Manager to disclose any perceived acts or circumstances of financial or ethical misconduct they may observe and which may impact the assets or affairs of the Fund or the interests of its unitholders. The Fund has always been dedicated to the principles of honesty and integrity in all matters concerning the conduct of its business and it expects and believes that all employees and contract personnel share this commitment. As a result of this policy change, any improprieties which are detected in the organization can be directly reported to, among others, the Chairman of the Committee, on a confidential basis. Further, any person providing a report pursuant to this initiative shall be protected from any form of retaliation by any Fund or Manager personnel.

Environment, Safety and Reserves Committee

The Environment, Safety and Reserves Committee is comprised of two unrelated directors and one related director. The Board believes that the industry knowledge of the related director benefits the review and decision processes of the Committee. It also believes that since two members, including the Chairman of the Committee, are unrelated, the independence of the Committee is not compromised. The duties and responsibilities of the Environment, Safety and Reserves Committee can be divided into two separate areas:

Safety and Environment

The obligations of the Committee relating to safety and environment matters include:

- review, approve and amend as required, internal environmental and safety policies and emergency response plans;

- review and approve strategies employed to manage risk in field operations;

- review internal and third party due diligence inspections; and

- review ongoing environmental and safety reporting and auditing results.

Twice yearly, the Board is presented with a Corporate Environmental Due Diligence Statement executed by senior management. The document certifies that, after due inquiry with the appropriate staff members, management is not aware of any significant environmental issues that have not been reported to the Committee and that appropriate procedures are in place to address any such issues, should they arise.

Reserves

The Committee is also responsible for monitoring the Fund's reserves. In this capacity the Committee satisfies its obligations primarily by:

- reviewing the procedures for providing information to the Fund's independent reserves evaluator;

- meeting independently with the independent reserves evaluator to determine the ability of the evaluator to report, without reservation, on the reserves of the Fund;

- reviewing the appointment of the independent reserves evaluator;

ENERPLUS RESOURCES FUND 2002 ANNUAL REPORT

- reviewing the available tax pools and future price/cost assumptions utilized in the analysis;
- reviewing the reconciliation of changes in reserves and future net revenue; and
- reviewing with management all information associated with oil and gas production and operational activities.

The Committee meets twice yearly and obtains, annually, a signed report from the independent reserves evaluator and a certificate of compliance from management.

Management Disclosure Committee

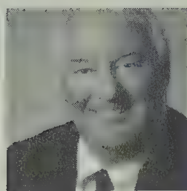
As a foreign private issuer listed on the New York Stock Exchange ("NYSE"), the Fund abides by applicable U.S. law and regulations and generally follows the recommendations of the Securities Exchange Commission ("SEC"). One of the recommendations of the SEC concerns the creation of a Disclosure Committee. In February of 2003, a Disclosure Committee was formed by members of management, (it is not a Committee of the Board), to specifically deal with the increasing disclosure obligations facing the Fund. The purpose of this management Committee is to determine the disclosure obligations of the Fund on a timely basis. The Committee reports to senior management, including the chief executive officer and the chief financial officer and also serves as the coordinating group for the Fund's public disclosure. Members of the Committee are selected by the Chief Executive Officer and the Chief Financial Officer.
The Committee's mandate includes:

- reviewing all periodic reports;
- reviewing current reports on relevant SEC Forms;
- reviewing press releases containing financial information or providing earnings distributions;
- reviewing presentations to analysts, investor conferences and rating agencies; and
- reviewing road show presentations to investors and other correspondence sent to unitholders.

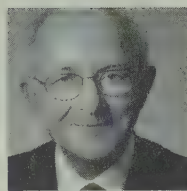
Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we have evaluated the effectiveness of the design and operation of our disclosure controls and procedures within 90 days of the filing date of this annual report pursuant to Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934 (the "Exchange Act"). Based on that evaluation, our principal executive officer and principal financial officer have concluded that these controls and procedures are effective. There were no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

Disclosure controls and procedures are our controls and other procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified under the Exchange Act. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by us in the reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Directors



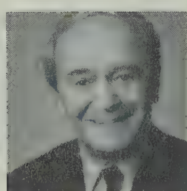
Douglas R. Martin[1][2][3]
President,
Charles Avenue Capital Corp.
Calgary, Alberta



André Bineau[4]
Vice President,
Association de bienfaisance et de retraite des policiers et policières de la Ville de Montréal
Montréal, Québec

Derek J.M. Fortune[1]
Secretary/Manager,
Superannuation Fund,
City of Ottawa
Ottawa, Ontario

Gordon J. Kerr
President &
Chief Executive Officer,
Enerplus Global Energy Management Company
Calgary, Alberta



Robert L. Normand[1][4][5]
Corporate Director,
Montréal, Québec

Eric P. Tremblay[6]
Senior Vice President,
Capital Markets,
Enerplus Global Energy Management Company
Calgary, Alberta

Harry B. Wheeler[4][6][7]
President,
Colchester Investments Ltd.
Calgary, Alberta

Robert L. Zorich
Managing Director,
EnCap Investments L.C.
Houston, Texas

(1) *Corporate Governance & Human Resources Committee*
(2) *Chairman of the Board*
(3) *Chairman of the Corporate Governance & Human Resources Committee*
(4) *Audit & Risk Management Committee*
(5) *Chairman of the Audit & Risk Management Committee*
(6) *Environment, Safety & Reserves Committee*
(7) *Chairman of the Environment, Safety & Reserves Committee*

Officers

Gordon J. Kerr
President & Chief Executive Officer

Heather J. Culbert
Senior Vice President, Corporate Services

Garry A. Tanner
Senior Vice President & Chief Operating Officer

Eric P. Tremblay
Senior Vice President, Capital Markets

Robert J. Waters
Senior Vice President & Chief Financial Officer

Jo-Anne M. Caza
Vice President, Investor Relations

Daryl W. Cook
Vice President, Operations

Ian C. Dundas
Vice President & Director, Business Development

Wayne T. Foch
Vice President, Finance

David A. McCoy
General Counsel & Corporate Secretary

Daniel M. Stevens
Vice President, Development Services

Rodney D. Gray
Controller, Finance

Wayne G. Ford
Controller, Operations

Christina Meeuwsen
Assistant Corporate Secretary

Corporate Information

Operating Companies owned by Enerplus Resources Fund

EnerMark Inc.
Enerplus Resources Corporation

Legal Counsel

Blake, Cassels & Graydon LLP
Calgary, Alberta and Toronto, Ontario

Auditors

Deloitte & Touche LLP
Calgary, Alberta

Bankers

Canadian Imperial Bank of Commerce
Royal Bank of Canada
The Bank of Nova Scotia
The Toronto - Dominion Bank
Bank of Montreal
Citibank, NA, Canadian Branch
National Bank of Canada

Independent Reserve Engineers

Sproule Associates Limited
Calgary, Alberta

Stock Exchange Listings and Trading Symbols

New York Stock Exchange:	ERF
Toronto Stock Exchange:	ERF.un

Transfer Agent

The CIBC Mellon Trust Company
Calgary, Alberta
Toll free: 1-800-387-0825
Email: inquiries@cibcmellon.com

Head Office

The Dome Tower
3000, 333 - 7th Avenue S.W.
Calgary, Alberta T2P 2Z1
Telephone: (403) 298-2200
Toll free: 1-800-319-6462
Fax: (403) 298-2211
Email: investorrelations@enerplus.com

Enerplus Internet Site

Enerplus Resources Fund has a comprehensive website that provides investors with an immediate source of all public information with respect to the Fund. The following documents are available at **www.enerplus.com:**

- Unit Trading Information
- Tax Information
- Recent Presentations
- Historical Distribution Tables
- Adjusted Cost Base Calculator
- Corporate Governance
- Annual and Quarterly Reports
- News Releases
- 15 Minute Delayed Stock Quote
- Distribution Reinvestment and Unit Purchase Plan
- Important Dates and Events

Annual General and Special Meeting

Unitholders are encouraged to attend Enerplus Resources Fund Annual General and Special Meeting being held on:

Wednesday, April 23, 2003
at 10:00 AM, local time,
at The Metropolitan Centre
333 - 4th Avenue S.W.
Calgary, Alberta

Those unable to attend are asked to sign and return the Form of Proxy contained with this annual report.

For more information, visit our website: www.enerplus.com

Abbreviations

AECO"C"/NIT	Alberta Energy Company interconnect with the Nova System
ARTC	Alberta Royalty Tax Credit
bbl	barrel
bbl/day	barrel(s) per day
Bcf	billion cubic feet
BOE(s)	barrel(s) of oil equivalent (6 Mcf gas = 1 bbl crude oil)
BOE/day	barrel of oil equivalent per day
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/day	thousand cubic feet per day
MMbbl(s)	million barrel(s)
MMBOE	million barrels of oil equivalent
MMbtu	million British Thermal units
MMcf	million cubic feet
MMcf/day	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
RLI	reserve life index
TSX	Toronto Stock Exchange
W.I.	percentage working interest of ownership
WTI	West Texas Intermediate at Cushing, Oklahoma

Our focus is on *creating value* consistently over the long-term for our unitholders.

Gordon J. Kerr, *President & CEO*

RESOURCES FUND